Universidade do Porto

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# ENHANCING FLEXIBILITY AND ENSURING EFFICIENCY AND SECURITY: IMPROVING THE ELECTRICITY MARKET IN BRAZIL USING A VIRTUAL RESERVOIR MODEL

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# Abstract

The Brazilian electricity market is characterized by having around 75% of installed capacity coming from renewables and a large share of hydros with multiple agents coexisting in the same hydro cascades. Currently, it also contains certain particularities that distinguish it from other markets. Nevertheless, the conciliation between commercial commitments and the physical dispatch is not smooth: there is a lack of “trading opportunities” to encourage participants to comply with their contracts. Moreover, the Brazilian short-term market acts as a mechanism to settle differences rather than a true market, and neither the short-term price nor the dispatch schedules are determined by the market.

In order to overcome these issues this thesis proposes a new market design. The proposal demands the deployment of a more market-oriented framework based on the concept of energy right account, which is designed to represent how much energy is ‘virtually’ stored in the reservoirs. It aims at enhancing the flexibility to enable market participants to endure their contracts, while still ensuring the efficient use of the energy resources in the hydro cascade and maintaining the current security supply level of the country. In this market two worlds would coexist: the real one, associated with the power system and with physical effects; and the virtual one, related to the settlement system and with commercial effects. Finally, the exposed position of market participants will be measured by their virtual successful bids into a new short-term market.

To simulate the behavior of the hydros in this new market design, an Agent-Based Model using the reinforcement Q-Learning algorithm is adopted. Companies prepare their bids depending on the level of their reservoirs, the amount of energy committed through bilateral contracts, and month of the year, which is associated with water inflows into the system, the short-term market ceiling price and the electricity demand. Considering an entire year, their goal is to optimize their monthly revenues (i) avoiding negative exposures in case of ending up providing successful bids lower than bilateral contracts and (ii) getting extra profit in the short-term market when there is more energy than the ex-ante contracts. The simulations used real data from the Brazilian power system embracing 3 years (2012, 2013 and 2014) and more than 125 hydro power plants, representing more than 98% of the total hydro capacity installed of the country.

The results indicate that the proposed market design maintains the current levels of the efficiency and security, while enhancing the agents’ level of flexibility to sustain contracts. As a consequence, the management of (virtual) reservoirs is under the responsibility of each hydro, which could (virtually) save water according to their own risk perception. In doing so, the operation of the physical system is not affected, ensuring the efficiency of the hydro cascades and maintaining the current security of supply level. The results obtained also demonstrate that the final monthly short-term market price substantially decreases in comparison with the current market.

# Resumo

O mercado de energia elétrica brasileiro é caracterizado por possuir cerca de 75% da capacidade instalada proveniente de fontes renováveis, e tem a especificidade de apresentar muitas centrais hidroelétricas pertencentes a diversos proprietários dentro das mesmas cascatas hídricas. Atualmente, contém certas particularidades que também o distinguem de outros mercados. No entanto, a conciliação entre os compromissos comerciais e o despacho das centrais não ocorre de maneira adequada: há uma falta de "oportunidade comercial" para os agentes suportarem os seus contratos. Além disso, o mercado brasileiro de curto prazo atua como um mecanismo para contabilizar e liquidar as diferenças entre a energia contratada e a energia gerada, e não como um mercado propriamente dito, e nem o preço de curto prazo nem os despachos são determinados pelo mercado.

Para superar esses problemas esta tese propõe um novo projeto de mercado. A proposta exige a implantação de uma estrutura mais orientada ao mercado e baseada no conceito de contas de direito de energia, que pretendem representar a energia que se encontra 'virtualmente' armazenada nos reservatórios. Esse projeto de mercado visa dar flexibilidade às centrais hidroelétricas para suportarem os seus contratos, e ainda garantir o uso eficiente dos recursos energéticos das cascatas e manter o atual nível de segurança energética do país. Neste mercado dois mundos coexistem: o real, associado ao sistema elétrico e com efeitos físicos; e o virtual, relacionado com o sistema de liquidação e com efeitos comerciais. Finalmente, a exposição dos participantes no mercado será medida por meio de suas propostas bem-sucedidas.

Para simular o comportamento das hidroelétricas neste novo projeto de mercado se utilizou um modelo baseado em agentes (*Agent-Based Model*) com o algoritmo de aprendizagem por reforço *Q-Learning*. As empresas preparam as suas propostas em função do nível de seus reservatórios, da quantidade de energia comprometida por meio dos contratos bilaterais, e dos meses do ano, que está associado com entradas de água no sistema, do preço teto do mercado de curto prazo e da demanda de eletricidade. Considerando-se um ano inteiro, o objetivo das empresas é otimizar as suas receitas mensais ao passo que atuam para (i) evitar as exposições negativas oriundas de propostas vencedoras mais baixas do que os contratos bilaterais e (ii) obter lucro extra no mercado de curto prazo quando há mais energia do que os contratos ex-ante demandam. Nas simulações realizadas foram utilizados dados reais do sistema elétrico brasileiro abrangendo 3 anos (2012, 2013 e 2014) e mais de 125 centrais hidroelétricas, o que representa mais de 98% da capacidade total instalada das hidroelétricas do Brasil.

Os resultados indicam que o projeto de mercado proposto mantém os atuais níveis de eficiência e segurança, ao passo que melhora a flexibilidade dos agentes para suportar contratos. Como consequência, a gestão de reservatórios (virtuais) é da responsabilidade de cada hidroelétrica, que pode (virtualmente) armazenar a água de acordo com a sua própria perceção do risco. Com isso a operação do sistema físico não é afetada, garantindo a eficiência na cascata de hidrelétricas e mantendo o atual nível de segurança energética do sistema. Os resultados obtidos demonstram também que o preço mensal do mercado de curto prazo diminui substancialmente em comparação com o mercado atual.

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## List of Acronyms and Abbreviations

AA - Adaptation Algorithms

ABM - Agent-Based Model

ACE - Agent-based Computational Economic

ACER - Agency for the Cooperation of Energy Regulators

*ACL* - Free Contracting Environment

*ACR* - Regulated Contracting Environment

ACO - Ant Colony Optimization

AFC - Average Fixed Cost

ANEEL - Brazilian Electricity Regulatory Agency

ANP - Brazilian Oil and Gas Regulatory Agency

ATC - Average Total Cost

AVC - Average Variable Cost

BRIX - Brazilian Intercontinental Exchange

CAISO - California ISO

*CCC* - Account of Fossil Fuel Consumption

*CCEAR* - Contract for Trade Electricity into the Regulated Contracting Environment

CCEE - Electric Power Commercialization Chamber

CEPEL - Research Center for Energy

*CDE* - Energy Development Account

CfD - Contract for Differences

CL - computational learning

CM - Capacity Mechanism

*CMO* - Operational Marginal Cost

CMSE - Electricity Sector Monitoring Committee

CNPE - National Council for Energy Policy

CVaR - Conditional Value at Risk

DECOMP - Medium-Term Operation and Planning Software

DAI - Distributed Artificial Intelligence

Disco - Electricity Distribution Company

DP - Dynamic Programming

EMTM - Electricity Market Target Model

EPE - Energy Research Company

ERA - Energy Rights Account

ERCOT - Electricity Reliability Council of Texas

ERGEG - European Regulator's Group for Electricity and Gas

ERI - Electricity Regional Initiatives

FC - Fixed Cost

FERC - Federal Energy Regulatory Commission

FS - Financial Settlement

GA - Genetic Algorithm

Genco - Electricity Generation Company

GSF - Generation Scaling Factor

*ICB* - Cost Benefit Index

IPP - Independent Power Producer

ISO - Independent System Operator

ISONE - ISO New England

LMP - Locational Marginal Pricing

MAS - Multi-Agent System

*MCP* - Brazilian Electricity Short-Term Market

MDP - Markov Decision Process

MgC - Marginal Cost

MIP - Mixed Integer Programming

MISO - Midwest Independent System Operator

*MLT* - Long-Term Average

MME - Ministry of Mines and Energy

MRA - Mechanism of Risk Aversion

*MRE* - Mechanism for Reallocation of Energy

NAE - Natural Affluent Energy

NAF - Natural Affluent Flow

NEWAVE - Strategic Model for Hydrothermal Generation by Equivalent Subsystems

NLP - Nonlinear Programming

NYISO - New York ISO

ONS - Brazilian system operator

OPF - Optimal Power Flow

OTC - Over-The-Counter

PG - Physical guarantee

PG_COVERAGE - Physical guarantee for physical coverage contracts purposes

PG_MRE - Physical guarantee for MRE energy allocation purposes

PJM - Pennsylvania-Jersey-Maryland Interconnection

*PLD* - Price for Settlement of Differences

PPA - Power Purchase Agreements

*PROINFA* - Program of Incentives for Alternative Electricity Sources

*PROCEL* - National Energy Conservation Program

PV - Solar photovoltaic generation

PX - Power Exchange

QL - Q-Learning

QSE - Qualified Scheduling Entity

Retailer - Electricity Retailer Company

*RGR* - Global Reversion Reserve

RTO - Regional Transmission Operator

SFE - Supply Function Equilibrium

TCU - Brazilian Federal Court of Auditors

*TEO* - Energy Optimization Tariff

TSO - Transmission System Operator

VC - Variable Cost

WPMP - Wholesale Power Market Platform

VRM - Virtual Reservoir Model

WWM - Wholesale Water Market

# List of Variables and Parameters

**VRM algorithm**

DEP - Deposit in the energy right account

$ERA_{start}$ - Energy Right Account in its initial stage

ERAadep - Energy Right Account after the performance of the due deposit

ERAaspill - Energy Right Account after the performance of the analysis regarding spillages

ERAaBID1 - Energy Right Account after the choice of BID1

ERAaBID1' - ERAaBID1 resulting from the linear programming

ERAaBID2 - Energy Right Account after the choice of BID2

ERAaBID2' – ERAaBID2 resulting from the linear programming

$ERAaBID2_{goal}$ - Energy Right Account target after the choice of BID2

$factor_{goal\_t}$ - Adjustment factor concerning the reservoir level goals

pBID - price bid

$PLD_{nh}$ - variable cost of the last non-hydro dispatched unit

$PLDreg\_uplim_t$ - regulatory ceiling price

$PLD_{final}$ – final short-term market price

$qCE_t$ - total quantity of the ex-ante bilateral contracts

qBID - quantity bid

qBID1 - qBID in the first bid

qBID1' - qBID1 resulting from the linear programming

qBID2 - qBID in the second bid

qBID2' - qBID2 resulting from the linear programming

qBID1suc - successful quantity regarding BID1

qBID2suc - successful quantity regarding BID2

$Q_{nh}$ - total demand to be supplied by non-hydros

$Q_h$ - total demand to be supplied by hydros

reward_BID1 - reward of the Q-learning algorithm regarding BID1 reward_BID2 - reward of the Q-learning algorithm regarding BID2

RC - Reservoir Capacity

$Reservoir\_level_{actual\_t}$ - the actual level of the virtual reservoir at the end of the trading period

$Reservoir\_level_{goal\_t}$ - the goal level of the virtual reservoir at the end of the trading period

VS - Virtual Spillage

**Q-learning**

a - action of the Q-learning

Q(s, a) - Q-values of the Q-learning matrix

s - state of the Q-learning

$\alpha$ - learning rate of the Q-learning

$\gamma$ - discount factor of the Q-learning

**Simulating Annealing**

$a_{policy}$ - action that seems the best

$a_{rand}$ - action randomly chosen

Temp - temperature of the Simulated Annealing

$\Phi$ - constant of the temperature-dropping rule

**Monte-Carlo simulation**

E(F) - estimate of expected value of F

F - function adopted in the Monte-Carlo sampling

N - size of the Monte-Carlo sample

V(F) - variance of F

$\beta$ - threshold for the convergence criteria of the Monte-Carlo sampling

$\sigma$ - standard deviation of the Monte-Carlo samples

# Chapter 1 – Introduction

## 1.1 Background and motivation for the thesis

The electricity industry has been changing over the years around the world from vertically integrated utilities to more decentralized structures and competitive electricity markets. These changes mainly aim at improving the efficiency of the sector, which contributes to decrease price through the increasing of the competitiveness levels of the electricity market, notably regarding the generation and retailing activities, once the distribution and transmission activities remain as natural monopolies.

Ever since, several electricity market structures are being designed and tested to ensure free access, guarantee fair competition, foster higher efficiency and decrease price, while maintaining or improving reliability and security of operation. Although Brazil has made significant progresses towards liberalization, the short-term market prices result from computational models driven by a minimal cost dispatch approach. The two main models used nowadays are [CEPEL, 2013]:

- NEWAVE (Strategic Model for Hydrothermal Generation by Equivalent Subsystems), which uses stochastic dual dynamic programming to perform studies up to five years ahead with an aggregated representation of hydropower plants (equivalent reservoirs) in order to determine the share of hydro and thermal generation that minimizes the expected value of the operation cost; and
- DECOMP (Medium-Term Operation and Planning Software), formulated as a linear programming problem to represent individually physical and operational constraints of the thermal and hydropower plants in order to determine the generation target for each power plant for the next 12 months.

One of the results provided by this “chain of models” (since the NEWAVE and DECOMP are run in a sequential way) is the Operational Marginal Cost (in Brazil known as *CMO*), which represents the variable cost of the most expensive dispatched generation resource. Then, the short-term price (known in Brazil as *PLD* – the Price of the Differences Settlement) is determined weekly based on the *CMO* calculation (and with the removal from the computation models of the internal submarket constraints and possible test generation). In *PLD* calculation the maximum and minimum short-term price limits set annually by ANEEL (Brazilian Electricity Regulatory Agency) are also considered.

So, as it can be observed, it is not the market through the interaction between its participants that determines the electricity short-term price, but basically two computational programs that value the present electricity cost considering, among other issues, future scenarios of water inflows. The water inflows are very crucial in these models because the Brazilian power system presents a massive penetration of hydros: around 75% of the electricity produced in Brazil comes from hydropower plants. Notwithstanding, during the years of 2007 and 2011 relevant problems related to inconsistencies in these models were detected, causing a large impact on the electricity sector, not to mention transparency and regulatory instability problems since the software codes have intellectual property rights and, therefore, are unknown by the market participants and the authorities[1].

The Brazilian power system is largely dominated by hydro companies that usually establish long-term contracts to build and operate power plants, and regarding which once a year it is allowed to perform the seasonalization process. Through the seasonalization process, the companies can set the monthly amount of the contracted energy and the monthly amount of the physical guarantee. The physical guarantee corresponds to the maximum energy production that can be maintained almost continuously over the years, and it has the value of a certificate that determines the total amount of energy that can be traded in the Brazilian electricity market.

So, there is an annual "window" to monthly distribute the physical guarantee and the contracted energy and, given that the centralized dispatch is carried out by the Independent System Operator (ISO) who doesn't consider the signed contracts, generators are not allowed to decide their own generation in order to sustain with their contracts. This fact can expose them to the risk of having to buy electricity in the short-term market at volatile prices to complete the energy committed in their contracts, if they are not dispatched.

Because of this, there is a mechanism to share among the hydros the aforementioned risk. Nevertheless, this mechanism (known as MRE – Mechanism for Energy Reallocation) is automatically performed, and the conciliation between the physical dispatch of the power system and the commercial commitments of the market participants is not smooth. In this market design it is missing flexibility to enable hydros to better address their risk of exposition according to their own risk perception and strategy.

In short, the problems that arise are, thus, related to the fact that:

- The codes of the chain of software used to run the centralized dispatch of the power plants are under intellectual property rights, and inconsistencies in the algorithms have a huge impact within the entire sector. Thereat, the confidence in the market can be affected;
- The Brazilian short-term market acts as a mechanism to settle differences rather than a true market. Neither party arrives at some point to make any short-term declaration of intention, nor is the *PLD* the result of the interaction between market participants; and
- In the medium and short-terms, generators are not allowed to define or adjust the amount of energy to endure with their contracts.

A solution typically adopted in other systems is the employment of a more market oriented approach. This market could enable all generators to offer, in the short-term, quantity and price bids, which would be used to set the market positions and, consequently, substitute the

[1] The market participants and authorities know the general algorithm and mathematical formulation behind these software, but not precisely how they were written, i.t. the lines of their codes.

seasonalization process and the MRE. As a result, the short-term price would be based on the interaction between market participants.

Indeed, there is a proposal from the Electric Power Commercialization Chamber (CCEE) that aims at adopting market mechanisms including [CCEE, 2012b]: (i) short-term prices closer to real time operation, like a day-ahead market; (ii) products traded in organized markets; and (iii) a centralized clearing and settlement procedure performed by an entity that should be also in charge of the monitoring of the participant's financial situation. If implemented, this new market framework, supported by liberalization principles, would require a new market structure and a different paradigm for market monitoring and oversight.

Nevertheless, particularly focusing on a power system with a large share of hydros, it becomes clear how important it is to coordinate the water stored in the reservoirs in order to safeguard the efficiency of using the energy resources, and the relevance of having enough incentives to ensure the security of supply of the country.

The presence of several owners in the hydro cascades endorses the market design based on the centralized dispatch in order to achieve the welfare maximization for the system as a whole, while the need to have a capacity mechanism in place suggests that it is important to maintain the current approach, both via the contracting scheme where loads must be fully ex-ante contracted and contracts physically backed and via the dispatch of the ISO (through the mechanism of risk aversion implemented in the NEWAVE and DECOMP).

## 1.2 Core of the market design and developed algorithm

Some studies aiming at expanding the employment of liberalized approaches in power systems with a large share of hydros propose mechanisms to induce adequate behaviors or implement schemes that lead to the cascade's optimization. However, this thesis innovates when addressing this issue in order to reinforce the freedom for both (i) the operation of the hydrothermal power system carried out by the ISO and (ii) the bidding strategies and commercial commitments of the market participants.

Regarding the enhancement of the flexibility to enable market participants to uphold their contracts, while still preserving the capacity of the system to efficiently use its energy resources and ensuring the current level of the security of supply, it was developed a new market design to be applied to hydrothermal systems with a large share of hydros. The conceptual market structure developed in this thesis is supported by the following proposed virtual reservoir model:

- Each hydro has a virtual account (like an energy rights account) that represents how much energy is virtually stored in his reservoir;
- For each accounting period, each account is fed by the fraction of the total affluent natural energy of the cascade proportional to the hydro's physical guarantee.

Then, the following sequence of events should be adopted:

1º The ISO does his work as it currently does (running NEWAVE, DECOMP as well as other software, procedures and schemes), and defines the amount of generation (physical dispatch) for each power plant. So, the efficiency of the use of the energy resources and the security of supply is maintained at the current levels;

2º It is calculated the "remaining demand", which is equal to the total demand minus the total dispatch allocated to the thermal power plants and other non-hydro generation sources;

3º A hydro virtual short-term market is established based on bids for this remaining demand:

   a. Regarding the price bid: hydros can bid a price between zero and a regulatory ceiling price defined by the regulatory agency;

   b. Regarding the quantity bid: each agent can offer values considering the balance of his account;

4º The final short-term price is calculated as a weighted average considering the hydro's clearing price and the variable cost of the last non-hydro resource dispatched by the ISO.

Through this market design, hydros would be responsible for deciding, in commercial terms, how much they want to withdraw from their virtual reservoirs to meet their contracts. Thereby, each generator will manage his contracts more efficiently, without affecting the real operation of the physical system. Furthermore, this model promotes a monitoring of the ISO performance based on comparisons between his decisions (the physical world) and the decisions of market participants (virtual world).

At the end of this process, the price no longer primarily results from a chain of computational software that may eventually present problems related to inconsistencies and transparency, but it is obtained through the combination of thermal costs originated from the ISO dispatch and the short-term price coming from the liberalized hydro short-term market. Thereby, this research addresses wholesale markets associated with power systems with high share of hydros of different owners in the same cascade, while maintaining the same level of operational security and efficiency of the use of energy resources, but increasing the level of flexibility regarding agents' commercial aspects.

In this proposed market, the interaction of the hydros is simulated by an algorithm developed as an Agent-Based Model (ABM). According to [Weidlich, 2008], within the last ten years, more and more researchers have developed electricity market models with adaptive software agents. This field of research is still growing and maturing, and many researchers have managed to replicate core characteristics of the today's electricity markets using models with adaptive and self-seeking agents.

So, the main contribution of this thesis can be outlined in two ways: first, it designs a new electricity market for hydros in Brazil, which is based on a decoupling between physical and virtual reservoir management in order to guarantee the proper energy security level and the optimization of the operation of the hydropower plants in the cascades; and second, it develops a new market simulation tool to provide a realistic representation of those parts of the power system that are important to this analysis.

## 1.3 Objectives

The main objective of this research is to develop a new market design based on bids to be applied to power systems having a large share of hydros. In order to achieve the main objective stated above, this work pursuits the following specific objectives:

- Develop the virtual reservoir model designed to enhance the flexibility of market participants to comply with their contracts while ensuring the same levels of security of supply and efficiency in the use of energy resources;
- Implement a proper agent-based simulation model focused on the behavior of the agents in the new proposed short-term market; and
- Analyze the performance of the proposed model taking into consideration real data from Brazil.

According to [Li et al., 2011], since electricity markets are still under construction, many interesting and meaningful issues related to bidding optimization under various possible market designs should be investigated and tackled. So, the focus of this work is the proposed virtual reservoir model and its simulation through an agent-based model. Then, we analyze the behavior of the large majority of the Brazilian hydropower plants in this new framework.

Particularly, the proposed model intends to improve the Brazilian short-term market (where the differences between the contracted energy and the amount of generated / consumed electricity are calculated and settled), by adding the virtual electricity hydro short-term market. Finally, the proposed model is integrated with the already existing combination of bilateral contract markets, both within the framework of the Regulated Contracting Environment – *ACR* and the Free Contracting Environment – *ACL*[2].

## 1.4 Research question of the thesis

In a wide perspective, this thesis has the following research question:

- Having in mind hydrothermal systems with a large share of hydros with multiple owners in the cascades, how will the electricity market based on bids and virtual reservoirs operate, and how should it be designed to enhance the flexibility of market participants to comply with their contracts while ensuring the same levels of security of supply and efficiency in the use of energy resources?

The idea behind the aforementioned question is to produce knowledge about a market design characterized by the possibility of ISO to physically operate the power system (the ISO will be in charge of the global optimization of hydro's cascades, deciding how much electricity should be produced by the hydro and thermal power plants in each accounting period) while allowing each generator to manage its bilateral contracts according to its level of risk perception since

[2] In Brazil, the *ACR* corresponds to long-term contracts, usually up to 35 years, established by a PPA - Power Purchase Agreements, signed between generators and distribution companies if generators are successful in a national public auction with descending price. The *ACL* corresponds to a free contracting environment where two parties agree on how a particular agreement will be settled in the future.

they can bid in a short-term market to endure their positions (mechanism that will be included in the Brazilian short-term market).

## 1.5 Outline of the thesis

The thesis is organized in 6 chapters as follows.

In this chapter (Chapter 1) it is presented an introduction to problems that are recognized in the current Brazilian electricity market and which motivated this research, as well the main objectives, concerns and the proposal that was developed to address these issues.

Chapter 2 provides the fundamental knowledge regarding electricity markets. Thus, it theoretically discusses four electricity industry structures, the sequence of markets, and the relation between electricity markets and the physical operation of the power systems. The analysis of this relation is divided in two parts: market design completeness in the short-term (i.e. how is the conciliation between the dispatch schedule and the commercial commitments obtained?), and the market design adequacy in the long-term (i.e. how does the short-term market allocate feasible technologies in order to add new capacities?)

Then, Chapter 3 focuses on the Brazilian electricity market, and its features are broadly discussed. Besides a wide presentation about this market, including the recent electricity reforms, its current quantitative aspects, and the legal and institutional frameworks, it is performed a specific analysis of the Brazilian case regarding the conciliation between the electricity markets and the physical operation of the power system. Then, focusing on this power system, three concerns are discussed: efficiency in the use of the energy resources; security of supply and some capacity mechanisms; and the need to improve the flexibility to enable generators to comply with their signed contracts. At the end, both the market adequacy and completeness are also examined.

Considering some elements of a centralized and decentralized market-based economy, the proposed model (Virtual Reservoir Model - VRM) is developed in Chapter 4. It is designed to enhance the flexibility of market agents to uphold their contracts while ensuring efficiency and security of supply of the power system. Moreover, some modeling alternatives to better understand generators' behavior are discussed and the Agent-Based Model (ABM) including the Q-learning technique is deeper studied. Finally, it is established the algorithm to simulate the generators' behavior.

Chapter 5 details the validation of the developed algorithm and presents results obtained withseveral simulations of the Brazilian electricity market. Scenarios were implemented in the algorithm in order to allow comparisons. Moreover, the results of these simulations are presented together with the relevant evaluations and discussions.

Chapter 6 sums up the main results and conclusions in order to clarify the contributions of the thesis. It also enumerates a number of prospects for future works to be developed.

# Chapter 2 – Electricity Market Designs

The electricity sector is a complex industry and greatly differs from other markets since it is required to balance the demand and production at every moment and to deal with the inevitability of equipment failures that request resources backup (generation capacity and electricity transmission and distribution infrastructures). Moreover, since several countries embarked on a path characterized by market liberalization, the electricity markets around the world are continuously evolving and their social, economic and political particularities play an important role on this evolution. As pointed out in [IEA, 2005], the establishment of market institutions that effectively serve their purpose largely depends on the point of departure with each country, and this process has not yet been completed anywhere in the world.

The objective of this chapter is to consolidate the fundamental knowledge regarding the electricity markets in order to enrich the comprehension of real-world cases and deal with their elements to properly analyze market designs. Thus, it will be presented the electricity industry structures (Section 2.1), a briefly classification of markets (Section 2.2), an overview of the sequence of markets (Section 2.3), and the meet between the electricity markets and the physical operation of the power system (Section 2.4). Moreover, the discussion regarding the Brazilian electricity market (which is the case of study used in this research) starts here, but under a general perspective.

In addition, given the research of the thesis, the focus will not be on transmission activities, but on the electricity producers and sellers (generation) and their potential buyers (distribution companies, retailer companies, and consumers), especially considering the transactions into the electricity market.

## 2.1 Four electricity industry structures

The liberalization of the electricity market is a pathway to promote a higher economic efficiency and technical innovation by introducing certain incentives. However, it should be clarified that the liberalization is not an end in itself. And it is not enough to achieve a higher efficiency and innovation since these goals can also be seen as intermediate ones.

In short, during the 90's there was a debate all around the world concerning the move and the transition from the Welfare State to the Deregulated State, which brought changes in numerous economic sectors. Regarding the electricity sector, and as ascertained by [Sioshansi, 2006], during this time the motivations for changes were above all: (i) inefficiencies of large dominant players, where the majority were stated-owned companies; (ii) public debts, where the sale of state-owned asset could bring some relief to the heavily indebted governments of the time; (iii) inadequate investment in infrastructures, which was among the primary reasons for many developing economies to liberalize their systems and attract foreign investment; and finally (iv) because central governments could no longer cope with the growing complexities of forecasting, financing, constructing, operating and maintaining the power system.

In Brazil, besides the special concern related to the so-called “principle of continuity of public service”, federal laws[3] were elaborated also to seek low tariffs, and this was done by consolidating the coined concept of “principle of reasonable tariffs”. Thus, the two main improvements to the society particularly considered in the analysis of this research (which can be seen as one of the final goals of the liberalism), and which have driven most of the countries (including Brazil) to restructure its electricity sector, are as follows:

- decrease of electricity prices and tariffs, which denotes an immediate enjoyment for all consumers; and
- increase of the private capital to the operation, maintenance and expansion of the power system, which for the society it is connected with the pursuit of sustainability, resilience and efficiency of the electricity service in the long-term.

Among the incentives that have the purpose to promote and consolidate the pathway to more liberalized systems, above all there is the introduction of competition between the market players. Competition is the main engine of these effective incentives: competition exposes market players to certain risks but also provides rewards for taking risk and performing better than one’s competitors. So, it is useful to begin this analysis by having a look in the electricity industry structures, and do this according to their level of competition. Considering this, [Hunt & Shuttleworth, 1996] bring interesting insights by organizing the electricity industry in the following four categories:

- Model 1 – Vertically integrated utility;
- Model 2 – Competition with a single buyer;
- Model 3 – Competition in the wholesale market; and
- Model 4 – Competition in the retail market.

This classification of electricity industry structure tracks the philosophy of the electricity market liberalization and can also be viewed as a process that starts introducing competition into a certain part of the value chain to further enlarge it as many as possible. By doing so, it is important to highlight that the price must be seen as the connecting link into the market. In other words, prices direct decisions and efficient decisions depend on correct price signals. This explains why competitive market prices should reflect the real costs and benefits of producing, transporting and consuming electricity. And as stronger, more transparent and long term visible market signals are better.

Besides price, another issue should also be emphasized. Whereas this process progresses, it is also crucial to decrease the transaction cost, otherwise the developing of the next level of

[3] The relevant federal laws particularly relate with the principle of reasonable tariffs in the electricity sector are: Law 8987/1995, which regulates the system of concessions and permission regarding the provision of public services provided in the Federal Constitution; Law 9074/1995, which sets standards for grants and renewals of the concessions and permissions of the public services; Law 9427/1996, which establishes the Brazilian Electricity Regulatory Agency (ANEEL); Law 10438/2002, which, among other points, provides guidelines for universal public service of electricity and creates the *PROINFA* energy renewable program and the CDE energy development account; Law 10848/2004, which provides rules regarding the commercialization of electricity; and Law 12783/2013, which deals with the renewals of concessions of generation, transmission and distribution of electricity.

competition can be counterproductive. This is particularly important in Model 4, where a large number of small buyers are active in the market. And one way to overcome this barrier is to develop well organized and transparent markets.

In addition, another feature of this process is the increased level of complexity that arises when the market rules should substitute the centralized planning management. So, new markets are created to feed the growing demand for a larger market-based economy. For instance, to keep to physical power system property operating, the system operator needs to count with a firm reserve of resources in order to deal with unexpected events. If it is designed that this ancillary service will no longer be an obligation to be fulfilled according to a command and control hierarchy, then a reserve market must be created to occupy this “space”. Therefore, the price signal from this specific market should now substitute, for instance, some instructions and procedures specified in the grid code. The more a market-based electricity industry is implemented, the more market tools are needed. Then, a dilemma in designing new markets appears when the increase of complexity, detail, accuracy and sensitivity of market signals also rise the potential for economic abuse by certain players [Harris, 2006]. Again, it is also vital to develop organized and transparent market to deal with such issue.

At a certain point of this ongoing change from a centralized planning management to a market-based economy, it can be seen as a matter of faith that things will work appropriately just because markets provide it by themselves. However, expectation about the *invisible market hand*, the metaphoric concept conceived by Adam Smith, has shown to be insufficient. As observed by [Hawken *et al.,* 1999], for all their power and vitality, markets are only tools. Besides that, this author also notes that markets make a good servant, but a bad master and a worse religion.

Having said all this, it should be underlined that the move from Model 1 to Model 4 should not be taken as a universal roadmap. When moving from one model to another, there are trade-offs that must be taken into account. So, it is essential to perform a comprehensive analysis in order to consider the context of the current market design and the advantages and disadvantages of the further model for one particular electricity market. As noticed by some authors [Harris, 2006; IEA, 2005], differing nature of drives in different countries means that there is not a one-size-fits-all solution.

### 2.1.1 Model 1: Vertically integrated utility

This model is characterized by the vertically integrated system, whether state or privately owned. In this model one utility owns and operates all the generation power plants as well as the transmission and distribution infrastructures, and is responsible for the retail of electricity to the final consumers. Thus, the vertically integrated companies cover all the activities of the electricity industry and they operate alone in specific or concessioned territory. This model is illustrated in Figure 2.1.

The utility has the monopoly over the production, transmission and distribution activities. In return for the monopoly, the utility has the obligation to serve (i.e. to provide electricity to everyone in its area) at a tariff which is regulated considering the cost of service.

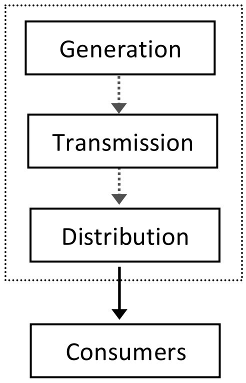


**Figure 2.1 – Model 1: Vertically integrated utility, based on [Hunt & Shuttleworth, 1996]**

One of the advantages of this model is related to the economies of scale that the company can obtain by building larger plants and covering the territory efficiently [Belyaev, 2011]. Other advantages are: economies of coordination, especially the coordination of the dispatch of the generation power plants, once the system operator can command and control the operation of the plants; and greater ability (if compared with Models 3 and 4) to accommodate social and strategic policy obligations such as uniform pricing price across areas with unequal cost, rural electrification, subsidies for poorer people and diversity of the generation mix [Hunt & Shuttleworth, 1996].

The most important disadvantage is related to the fact that there is no competition in any of the segments of the value chain, so there are no such previously mentioned incentives to seek for efficiency and innovation. The process to achieve low tariffs is ruled by the cost-based principle, which can include some incentive regulation approaches, but essentially remunerates the company providing a return on the assets and an amount in order to recover the incurred costs. Thus, the quest for low tariffs will not occur through market-based principles, when market rewards are reached when one company performs better than others, but through regulation based on cost of service. And due the asymmetry of information intrinsically present in this kind of regulation, the adequate remuneration is not guaranteed.

Others concerns about Model 1 are connected with who supports the investment risks, how can the customers services be improved and how can innovative technologies be developed. [Sioshansi, 2006] observes that in this model taxpayers bear all investment risks and there is generally little or poor accountability. Moreover, there is not a effective pressure to improve customer service or engage in technological innovation. Thus, vertically integrated companies tend to be over-staffed and inefficient, and with scant financial scrutiny the stated-owner companies tend to underperform.

In addition, and taking into consideration the history of the electricity sector[4], this model is dominated by the public investment. In other words, it is the State budget that provides the

[4] Typically the electricity sector around the world started small, where the purpose was just supply a city, and usually operated by a private company. As it was enlarging and connecting with other power system (achieving thus the level of a state/province or country), the State assumed the electricity as a public service and these private companies became public ones: the vertically integrated companies.

financial resources to expand the power system. However, one of the reasons that justified switch over from this model, as mentioned in the Section 2.1, was the need to have private investments to expand the electricity infrastructure. This is a fundamental and challenging issue, mainly to developing economies that need to add large amounts of installed capacity into the electricity matrix every year to meet the growing electricity demand. To move forward in the liberalization process it should be considered that, beyond a certain point, the State may not be in charge of the energy security of supply of the country. Rather than this, it is the market-based economic, considering essentially the price signals and the market efficiency, that will determine when and where new power plants will be built, and what kind of technologies and fuels these power plants will use.

In order to advance to the next models, it is necessary to implement the unbundling process in the electricity sector. The vertically integrated company must be divided to promote competition where it is possible (namely in generation and retailing activities, since the distribution and transmission activities typically remain as natural monopolies).

By doing this, contracts must substitute the command and control management of the vertically integrated company (i.e. contracts should somehow mimic the structure of an integrated company). In addition, contracts are also used to manage the market risks (by reallocating or sharing or spreading the risk) and to deal with transaction costs (i.e. cost of negotiating, executing and enforcing payment) and to provide better incentives (to avoid non trustful behaviors) [Hunt & Shuttleworth, 1996].

### 2.1.2 Model 2: Competition with a single buyer

With the implementation of the unbundling process, new agents known by Independent Power Producers (IPP) arise and become crucial. These new companies have free access to the transmission and distribution lines as prerequisite to allow them to sell electricity and promote a fair competition. Besides that, it is expected the divestiture of the vertically integrated company (at least a segregation in accounting terms) in the following independent companies: generation company (Genco), transmission company, and distribution company (Disco).

Apart from the promotion of competition, the unbundling between distribution and generation activities is also relevant to avoid the perverse self-dealing of a Disco that owns generators and will prefer to purchase from their affiliates, even if the price is higher than other producers, because the excessive cost can be passed on to consumers. In Model 2 (as well in Model 3), the Disco still have the monopoly over the consumers (this monopoly is lost in Model 4), that is, the distribution wiring activity is not separated from retailing.

The transmissions companies from now on (Models 2, 3 and 4) will be independent companies with the function of transmitting electricity from the generation to the distribution centers. Like the distribution wiring activity, this activity is seen as natural monopoly, and over this condition it remains regulated.

Another agent that appears in this model is the Purchasing Agency, normally carried out by public administration. Figure 2.2 presents a schematic representation of this model (the gray area highlights where competition occurs). The Purchasing Agency buys large amounts of electricity (i.e. a wholesale purchase) from the IPPs on the basis of long-term contracts with defined date and terms of delivery [Belyaev, 2011], and at a price that can be determined by a competitive mechanism[5] being conducted by the State taking into consideration a centralizing energy planning. So, the Purchasing Agency exercises a monopsony, being the only buyer to purchase energy from all generators. In Brazil, the figure of the Purchasing Agency is essentially incorporated by the Energy Ministry, and the competitive mechanism takes the form of national public auctions.

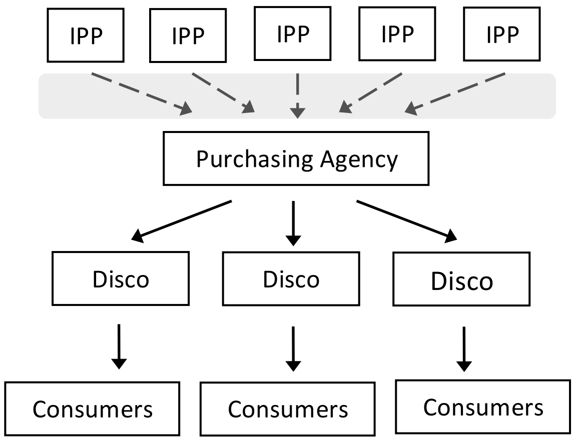


**Figure 2.2 – Model 2: Competition with a single buyer, adapted from [Hunt & Shuttleworth, 1996]**

The security of supply addressed by a central planning entity is a hallmark of both Model 1 and Model 2. One feature of these two models, as a consequence of the central planning, is the fact that risk regarding the impacts of uncertainties in future conditions or erroneous decisions is with the costumers, not with the producers. When moving from Models 1 and 2 to Models 3 and 4, this risk also moves from the consumers to the producers.

As the cost to generate electricity is around 50-60% of the final tariff, excluding tax and subsidies, Model 2 enables the realization of the main part of the potential effect of competition [Belyaev, 2011]. In Brazil, not considering sector charges and taxes, generation costs represent about 50% of the final consumers tariff (plus 10% from transmission and 40% from distribution) [ANEEL, 2014c]. If compared with the Model 1, the advantage of Model 2 is, due the implementation of public auctions, to bring competition to the tariff formation and substantially to incentive lower tariff.

The mentioned long-term contracts, known as PPA (Power Purchase Agreements), enable the generation and distribution companies to contract in advance for several years. The main elements of these contracts are the payment for availability ($/MW) and the payment for energy ($/MWh). As point out by [Hunt & Shuttleworth, 1996], the clauses of the contracts of Model 2 (PPA) will typically address an availability payment (designed to cover fixed costs, i.e. the investment on the power plant), and an energy payment (set to cover the variable cost of generation, i.e. the cost to run the power plant).

[5] [Hunt & Shuttleworth, 1996)] call "bidding systems" the competitive mechanisms of the Model 2. As counterpoint, these authors associate the Model 3 and Model 4 with the expression "competitive markets".

In addition, since the power plant must have an incentive to be available during the contract term, the availability payment must be linked with the actual availability of the plant. However, if the power plant is not actually running, it is difficult to assess its availability, which can require an oversight effort of the regulator over the facility.

From the producers' point of view, to contract in advance means to close agreements (defining, among other conditions, the price, date to start the delivery of electricity and period of supply) before even beginning of the construction of the power plant. This condition is really helpful to avoid the risk of investing large amounts of money to build a power plant and, then, to compete to sell electricity on daily bases with prices varying each hour in order to try to recover both the fixed and variable costs. These long-term contracts are also supportive to a financial modeling that enables entrepreneurs to take loans and leave as a guarantee the future revenues of these contracts. Comparing with Models 3 and 4, Model 2 facilitates generators to raise capital.

From the consumers' point of view, these long-term contracts represent a mechanism to address the security of supply once new capacity is added to the power system. In other words, the long-term contracts with availability payments can be seen as a capacity mechanism, which is used to conciliate the generation expansion with the demand growth.

Regarding the tariff formation, Model 2 can be designed to provide a tariff for the final consumers calculated by the weighted average of the successful bids of the public auctions. In this case, companies are remunerated following the "pay-as-bid" principle.

### 2.1.3 Model 3: Competition in the wholesale market

To leave Model 2 and to adopt Model 3 there is a change in the type of competition at the wholesale level. This change corresponds to the switch from a single buyer (the monopsony Model 2) to several buyers (the distribution companies, admitting that the separation from retailing did not occur yet), as shown in Figure 2.3. Thus, competition in Model 2 occurs in the same level (wholesale) of Model 3, but through a different structure (Model 2 through a single buyers; Model 3 through several buyers).

The Discos have to buy electricity on behalf of their consumers, and still maintain the monopoly over the retail energy sale, which guarantees that the Discos are the unique retailers into the market. By the way, if competition is allowed in the retail level, the Discos should not have the monopoly over the final consumers, then these consumers could freely choice their electricity supplier, and there would be competition in the retail level, which defines Model 4. Nevertheless, in real-world electricity market both Model 3 and Model 4 can coexist just defining which kind of consumers are eligible to choose their supplier (generally the classification is based on how much energy a customer consumes or based on the voltage connection level).

Comparing to Model 2, the purpose of Model 3 is to enlarge the competition by adding more participants into the market. However, by doing so, there may be a weakening at the consumers' side since one single buyer (a monopsony) can have more bargaining power to push prices down than a market with several buyers. This can be seen as disadvantage of

Model 3 over Model 2. It is also relevant in this point that the complexity level of Model 3 (which also increases in Model 4) is larger than in Model 2.

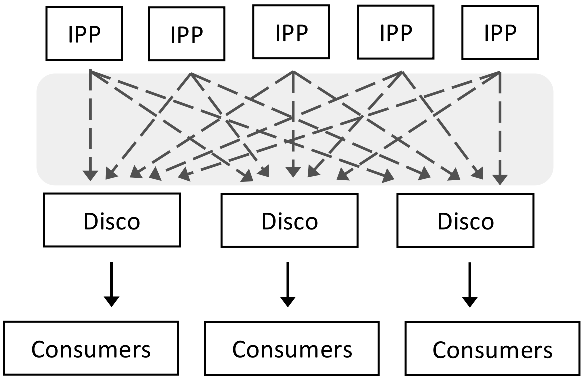


**Figure 2.3 – Model 3: Competition in wholesale market, adapted from [Hunt, 2002]**

In Models 3 and Model 4 the market risk is with the producers, while in Models 1 and 2 the market risk is with the consumers. This occurs because long-term contracts, in one hand, reduce the risk of generators losing their market when new technologies enter into the market and, in other hand, consumers assume the risks through the long-term contracts and bear it during the long life of capital assets [Sioshansi, 2006]. [Hunt & Shuttleworth, 1996] recall that, since in Model 2 the generation companies are insulated from the technology and other risk associate with the market, this will undermines the superior incentive to innovation inherent to a more market-driven situation (stronger presented in Model 3 and Model 4). On other hand, long-term contracts will also limit the market power of the producers [Rangel, 2008] [Karthikeyan *et. al.*, 2013] [Brunekreeft et al., 2005].

Liberalized markets create a new investment paradigm in which decisions are taken under competitive pressure. So, regarding the security of supply, when risks are moved from consumers to producers, capital-intensive technologies with long construction times are view with great skepticism, even if running cost are low. Then, market players prefer projects with short time implementation that can be built in smaller units, and competition also pushes investment decision to the last minute, which can provide more efficiency but puts policy makers under pressure to intervene [IEA, 2005].

Model 3 (and also Model 4) will break up the centralized decision-making process of Models 1 and 2, switching it to a decentralized process where market players take decisions considering markets signals. A generator will build a power plant if the market price is expected to cover both the construction and operation costs. So, many aspects of the choice regarding when to build and what to build are now in the hands of the entrepreneurs. Therefore, the question is if Models 3 and 4 have sufficient incentives to promote the generation capacity adequacy, or if new market-based schemes should be developed to meet this issue. These queries and doubts clarify why nowadays capacity mechanisms are in the agenda debate of policy makers, regulators and entrepreneurs.

Another particularity of Models 3 and is the fact that, since the market doesn't recognize fuel poverty (i.e. the market doesn't act considering strategic policies for the country regarding diversity of the generation mix), government intervention is required to alleviate it by mechanisms such subsidy, cross subsidy and discriminatory pricing [Harris, 2006], whereas Model 2 makes it easier for governments to achieve social policy objectives such diversity of generation power plant and rural electrification [Hunt & Shuttleworth, 1996].

In Model 2 a generator needs to participate of the public auction promoted by the Purchasing Agency to try to sell electricity. If the bid is a successful one, then they will sign long-term contracts with the distribution companies. This structure is known as “competition for the market”. In Models 3 and 4 there is an organized market in which they can try to sell their electricity, which is recognized as “competition in the market”. So, unlikely Model 2, which is governed by long-term contracts and competition takes place just during the time where public auctions are open to bids, Models 3 and 4 are influenced by short-term transactions and competition continuously occurs into the short-term markets, despite this is also implemented through bids.

One difference (despite this does not correspond to an advantage, as can be noted in Sections 2.3.2 and 2.4) between Model 2 when comparing with Models 3 and 4 with uniform price is that the tariff of the final consumers can be designed to be the weighted average of the successful bids in the public auctions, and not the clearing price of a short-term market based on Models 3 and 4. In the former, buyers pay according to each successful bid (i.e. pay-as-bid), while in the latter buyers have to pay to all successful sellers the price of the last unit dispatched (i.e. uniform price).

Figure 2.4 shows that in Model 2 the “producer surplus” (dotted area) belongs to consumers while in Models 3 and 4 with uniform price it belongs to producers. The gray area represents the remuneration paid by consumers to the producers, and the hatched area represents the producer surplus when it is assigned to the consumers. So, regarding the tariff of the final consumers, the equations 2.1 and 2.2 represent these two approaches.

$$Tarrif_{Model\ 2} = \frac{\sum_i^n p_i \times q_i}{\sum_i^n q_i} \tag{2.1}$$

$$Tarrif_{Model\ 3} = p^* \times Q^* \tag{2.2}$$

In these equations:

$p_i$: price bid of the agent i

$q_i$: quantity bid of the agent i

n: total of successful agents in the public auction

p*: clearing price

Q*: total quantity demanded

This issue is further discussed in Section 2.3.2, when addressing the cost structure of one power plant (specially the average total cost, average fixed cost, average variable cost and marginal cost) and the dispatch schedule of the system operator.

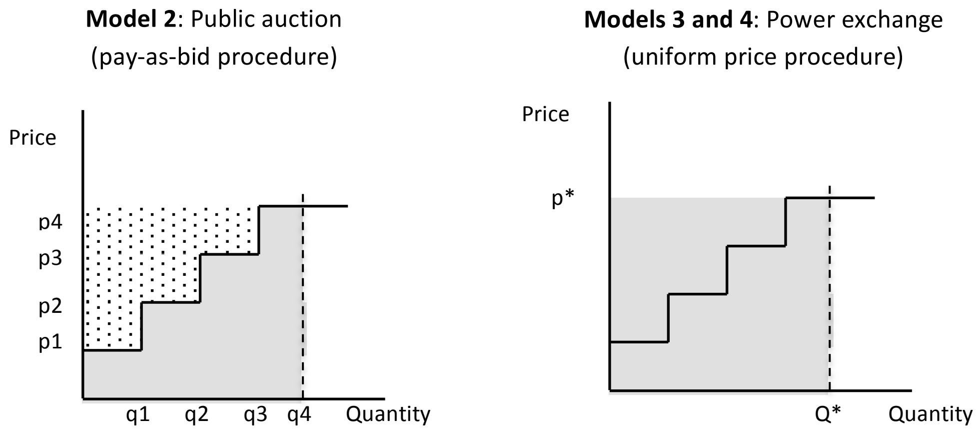


**Figure 2.4 – Producer surplus: Model 2 (like pay-as-bid) and Models 3 and 4 (if uniform price)**

### 2.1.4 Model 4: Competition in the retail market

Bring competition to the last level, the retail market, final consumers have the freedom to choose their suppliers. As noticed by [Hunt & Shuttleworth, 1996], Model 4 differs from Model 3 in that it is characterized by all consumers being able to choose the retailer, and this situation can be observed in Figure 2.5.

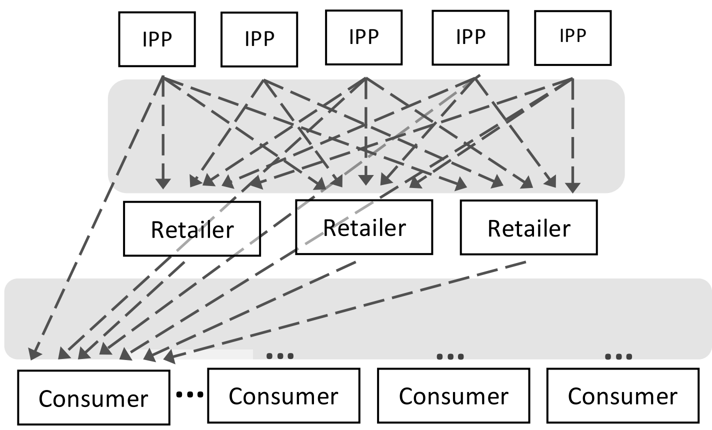


**Figure 2.5 – Model 4: Competition in retail market, adapted from [Hunt & Shuttleworth, 1996]**

In Model 3 Discos have the monopoly over the consumers, while in Model 4 the consumers can freely choose their electricity supplier, which can be a generator or a retailer company. In Model 4, the competition in the retail level implies the separation between electricity distribution wiring business and the retail business. This segregation will be done by divesting the existing distribution companies in two different business: the operation of the network (just concerning the distribution "wires"), and the retailing function (sale of "electricity" to consumers). Thus, the distribution companies (Discos) will not be allowed to sell electricity to the consumers. Instead of them, Retailing Companies (Retailers) will be in charge of buying electricity in the markets and to do these sales.

This situation is shown in Figure 2.5 by replacing all Discos by the Retailers in the same level where the Discos are in the Model 3. Considering that the transmission companies have not been represented in these figures since they deal with the operation of the network and don't have any commercial or physical relation with consumers regarding the trade of electricity (the relation between transmission companies and consumers mainly concern the payment of the use of network), for the same reason the Discos are not represented in Figure 2.5. Besides that, Discos (as well as transmission companies) have to provide free access to their networks to any consumers and producers.

On the other hand, the following issues were already mentioned for Model 3 and it can also be applied for Model 4: the construction of new power plants depends on the market price signals and there is not a central planning mechanism to determine where, when and what kind of resource should be deployed; if applied the uniform price settlement, the consumers lose the "producer surplus" (dotted area in Figure 2.4) since the tariff will be composed by the payment according to the marginal cost of the last dispatched resource; and the absence of long-term contracts also increase the opportunities to exercise market power by the producers, while the loss of the monopsony (single buyer model) can decrease the bargaining power of the consumers. Additionally, both the wholesale market (Model 3) and the retail market (Model 4) are not perfect markets, and this fact cannot be neglected.

Nonetheless, some issues of Model 4 really stands out if compared to Model 3. The monopoly of the Discos present in Model 3 doesn't give incentives to the Discos to buy the cheapest electricity since in any case its cost is passed on to the consumers [Belyaev, 2011]. Thus, usually in Model 3 the demand curve is inelastic and the bid of the Discos only includes quantities. On other hand, once consumers can freely choose their suppliers (Model 4), they should be more active into the market and, as a consequence, more aware of the market price fluctuations. There is, therefore, a higher chance to effective demand's responses.

However, the sharp increase of the number of buyers also complicates the activities of this market structure, and what must be seen as a bottleneck here is the eventual increase of the transaction cost. The transactional cost is strictly associated with the development and implementation of all necessary technologies and the transformation of the culture and behavior by the consumers, particularly the small ones, in order to allow the well-functioning of Model 4. Consumers cannot be expected to respond before prices rise sufficiently to offset transactional cost. Finding a way to take the wholesale price to the doorsteps of smaller commercial and residential consumers is, however, full with technical and economic barriers given the absence of the necessary metering equipment [IEA 2005] and the lack of management systems and accounting systems.

Nowadays, it is expected that this issue can be address by the smart grids and smart metering, once they should not only take advantage of the self-healing of the networks and to encourage the sustainable energies technologies, but also empower consumers by making available the information that they need to respond to price variations. To achieve this objective, price variation must be seen by the consumers into short time intervals in order to enable them to the move their consumption to periods with lower price.

Traditional electricity metering is generally performed monthly, and it doesn't take into account the consumption during the hours of the day. Regarding the operation cost of the power system, in some countries the tariff remains the same during a entire year. In other words, the tariff is only annually adjusted in order to pass on to consumers the real costs incurred in the operation. Thus, consumers will only feel the price variation on an yearly basis. In these cases, it may be unacceptable for a consumer to postpone his consumption, and there is no incentive to consumers to respond to price variation in order to save money.

Nonetheless, if price changes in each hour and consumers see these changes, they can choose the best time (lowest prices) into to next hours or days to perform certain tasks (and then consume the electricity that is needed). With an hourly price profile available, consumers' consumption is more manageable. In summary, if (i) consumers have the information regarding price some hours in advance, (ii) the price is settled hourly, (iii) electricity is metered by hour, and (iv) the cost of operation of the power system is passed on to the tariff on a more frequent basis, consumers have the incentives and can manage their consumptions to move them to the cheapest hours of the day.

So, both the development and implementation of smart technologies and the implementation of market rules (where hour price profile reflects the operational cost together with the adoption of monthly adjusted tariff) are important to overcome the high transaction cost and better explore the opportunities provided by Model 4. In addition, in order to make economic sense, the hourly price profile should be based on the real operational cost of the dispatched power plants.

Models 3 and 4 are based on organized markets where sellers and buyers trade in the short-term, usually with bids in each hour or half-hour, and the dispatch schedule corresponds to the successful bids of these markets. Therefore, these short-term market structures closely associate the real operation costs of the dispatched power plants with the wholesale prices. Then, these wholesale prices are passed on to consumers via the electricity tariff. However, as consumers generally pay the electricity bill monthly, it is necessary to meter the electricity at least on an hourly basis and to add, for example, a monthly tariff review.

Regarding Model 2, the long-term contracts usually have an availability payment to cover the fixed cost and an energy payment to cover the variable cost when the power plant is dispatched. The consumers always pay the fixed cost in their tariff, plus the variable costs of those power plants that are dispatched in that period. So, again the point here is when the tariff is adjusted to capture the real operation cost of the power system, and in which interval price can be defined and electricity can be metered. In the same way of Models 3 and 4, in Model 2 it is also necessary to have a short-term price formation and an electricity metering in hourly basis, together with a monthly tariff review.

Finally, it must be pointed out that the four types of market structures discussed in this section should not be seen as mutually exclusive. Overlays between these models can occur, in the sense that a combination of aspects of Model 2, Model 3 and Model 4 are possible since each model can be applied to different consumers' categories. Nevertheless, the organization in four market structure is very helpful to understand market designs and to clarify certain targets to implement competition.

## 2.2 Inside the structures: An overview of classification and sequence of markets

In the previous section it was discussed the basic electricity industry structures, and from this point it can be possible to better deal with a number of questions like the different levels of competition and its consequence over the tariffs and over the security of supply. Thus, this broader perspective allows an analysis considering some major improvements to the society and market designs to the electricity sector.

From now on, it is intended to go deeper in order to deal with different market classifications (Section 2.2.1) and with the sequence of market (Section 2.2.2). By doing so, it is not planned to cover all the possible variants regarding classifications and types of markets. Electricity markets have being particularly dynamic and since the liberalization process these markets are constantly evolving. Nevertheless, it is intended to present a comprehensive view of the most relevant and emerging markets. Finally, the relation between electricity markets and the physical operation of the power system is analyzed in Section 2.3.

### 2.2.1 Classification of the markets

Conceiving a market as a mechanism (with institutions, systems, rules and infrastructures) that allows buyers and sellers of a particular good or service to interact in order to facilitate an exchange, a market can have a large variation of "shapes". Regarding the electricity sector, markets can be classified in terms of the:

- marketplace (OTC and electronic trading platform);
- delivery time (short-term, medium-term or long-term);
- characteristic of the buyer (wholesale or retail);
- organization of the market (bilateral model or pool model); and
- price formation mechanism (bilateral, tight pool or loose pool).

#### *2.2.1.1 Marketplace: OTC and electronic trading platform*

Having in mind the characteristic of the power system, this classification is not linked with a physical marketplace such as physical location where peoples and/or firms meet to do trades. Rather than that, it is where market participants trade with each other through various communication platforms such as electronic trading systems. Following this, [Nasdaq, 2014] defines Over-The-Counter (OTC) as a decentralized market where geographically dispersed dealers are linked by telephones and computers.

Indeed, OTC is a case where market participants act quoting prices, and trades are executed between two participants. This negotiation is based in relations rather than in market rules. Furthermore, OTC cannot offer standard products. In this case, the market deals with tailor-made products, which means that buyers and sellers should negotiate all the items of the trade by themselves (it can be a time consuming task). Once they agree with these terms, they sign a contract that defines, among other conditions, the electricity price, data to start to deliver electricity, and the period of supply. However, brokers can act as intermediates between buyers and sellers, and in this case the OTC deals with standard contracts [Barroso *et. al.*, 2005].

The electronic trading platform is where virtually buyers and sellers can be presented in order to close an agreement in a faster manner and where products must be standardized. A power exchange[6] is an example of this marketplace. [Feltkamp & Musialski, 2010] gives a description of the power exchange as an available trading platform where electricity is traded as a commodity at the wholesale level and where participants such as generators, retailers or traders take inherent physical positions. [CCEE, 2012a] reveals that, in order to improve the organized markets, power exchanges have been created in several countries as a solution to facilitate and organize electricity trade by implementing the following measures:

- Standardization of products;
- Reduction of transaction costs;
- Transparency of market data; and
- Reduction of barriers for new market participants.

The auctions performed by the Purchasing Agency in the Single Buyer Model (Model 2) can be seen as electronic trading platform for long-term contracts where trades occur in a intermittently way. It is intermittent because it doesn't take place in consistent basis as it happens in power exchanges (e.g. regularly every day), but sporadically over a year or even within longer periods. This discontinuous bidding system is achieved by an electronic system to support the auction scheme, and each auction can be designed to have different rules. Products can also be customized to address each auction, and several different kinds of contracts can be established afterwards.

*2.2.1.2 Delivery time: short-term, medium-term or long-term*

Markets can offer products for short, medium and long-term horizons with different delivery time (e.g. daily, weekly, monthly or several years). Basically, for the short-term market, products have to be immediately delivered or delivered in a short period of time. Examples of types of market that deal with this these products are the "day-ahead" and "intraday" markets. Regarding the medium and long-term markets, products are traded through contracts with a promise of future delivery at a specified price.

As reported by [CCEE, 2012a], short and long-terms markets respond to different needs and they are complementary markets: while short-term contracts are mostly used to hedge volume risk, long-term contracts are applied to hedge price risk and to create the stability conditions to make new investments to assure the security of supply.

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[6] It should be commented that a "power pool" is also an organized market similar to a "power exchange". Nevertheless, the term "power pool" is more related to the early stage of the electricity market liberalism, where an asymmetric mechanism (with an inelastic demand represented by load forecast) was applied, and when it was mandatory for all market participants; while the "power exchanges" came in a more recent phase, and where there is typically a symmetric mechanism and they usually are not mandatory.

Lastly, it is worth making a few comments about the expression "spot market". [Hunt & Shuttleworth, 1996] explains that spot transactions are sales of an asset for immediate delivery, and that spot sales are often not accompanied by the creation of any formal contract (money pass from buyer to seller, and the asset changes hands in the opposite direction). However, these authors also emphasize that this "immediate" delivery can vary from industry to industry, recognizing that certain delays can exist.

In the electricity industry, the delay between agreeing a deal and making the delivery may be from minutes to hours (which is the case of the intraday market), or from hours to one day (as occurs in the day-ahead market), or even longer (case of intraweek or week-ahead markets). So, in the electricity sector the term "spot market" is frequently used to represent the "short-term markets". From a technical point of view, the term short-term market is more accurate than spot market, and so we will be using it along this research.

*2.2.1.3 Characteristic of the buyer: wholesale or retail*

This classification takes into consideration the definition of wholesale and retail market given by [Hunt & Shuttleworth, 1996]: when the final consumer[7] is the buyer, transactions correspond to retail transactions; when the buyer is a Disco or a Retailer, it is the case of a wholesale transaction. As addressed in Section 2.1.3, Model 3 illustrates the case of competition in the wholesale market, since the Discos have the monopoly over the final consumers, and Model 4 represents the competition in the retail market, once it is broken the monopoly that Discos had over the final consumers, and then these consumers can buy electricity from generators or retailers.

Because in the wholesale market the buyer is a retailer there is a large turnover involved in each trade. In the retail market, the volume of electricity bought in each trade depends on the size of the buyer. For instance, if the final consumer is a small consumer like a household or a local store, then the traded amount will be small. However, if the final consumer is a large industry, then there should be a larger turnover involved.

*2.2.1.4 Organization: decentralized or centralized market*

In [Barroso *et. al.*, 2005] it is presented a classification of electricity market models worldwide. According to these authors, from several market models implemented in different parts of the world, it is possible to distinguish two main types of market organization: (i) decentralized market or bilateral contract model; and (ii) centralized market or pool model.

In the decentralized market, transactions are freely negotiated between the participants, while in centralized markets the participants have access to the pool, and they must sell or buy electricity through the pool. Figure 2.6 illustrates the concepts of decentralized and centralized markets.

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[7] Final consumers are also called end user, and denote to the last point in the supply chain. In the electricity sector, they are those consumers that purchase electricity for their direct use rather than for resale or for use electricity into the process of electricity generation.

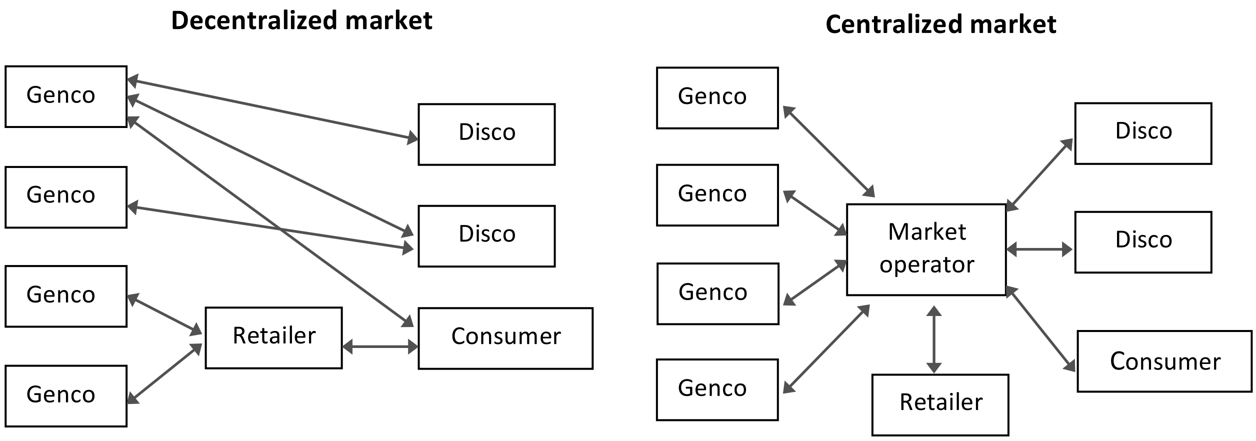


**Figure 2.6 – Decentralized x Centralized markets**

In the decentralized market, first of all, buyers must be found by the sellers (or vice-verse), and they should close a contract (setting price and quantity). When two parties mutually agree, then the contract is signed.

In this decentralized market, traders can make deals for physical delivery of electricity, scheduling those trades with the market operator[8], and having the operator working to deliver the scheduled power [Hunt & Shuttleworth, 1996]. In order to have their commitments scheduled, sellers and buyers submit notification, known as "physical notification" [Harris, 2006]. It is expected that these notifications are equal to their contract position.

These notifications represent the quantity traded by the contract, and the market operator will take them into account. As a consequence, this kind of contracts is called "physical contracts". Moreover, in this case it occurs what is recognized by [Harris, 2006] as a self-dispatch, which means that generators decide the dispatch of their own generating units by informing the market operator the amount bilaterally contracted. In addition, buyers will pay to the sellers the price previously agreed in these contracts.

In centralized markets, the approach envisages that buyers bid to purchase products, sellers bid to have their products delivery/dispatched, and the market operator will dispatch the generating units in order of the bids [Hunt & Shuttleworth, 1996]. In other words, producers submit their offer in the pool, which produces a stack and with this the market operator sends dispatch instructions [Harris, 2006]. So, the merit order is formed by the stacking of the producers bids, from the lowest price bid to the highest one, and it will be dispatch all units in this stack until the last unit fills in the sum of the total demand quantity bids.

Thus, in the centralized market the market operator uses the bids to dispatch the units, and he may not consider the contracts signed out of the pool. Therefore, considering only the

[8] In many market designs, the company that acts as a transmission provider also acts as a dispatcher and as a market operator. In the Brazilian case, there are three different players: transmission provider operates transmission lines; the system operator decides the dispatch schedule; and the market operator has the duty to settle the difference between the contracted and the verified energy.

dispatch schedule, this means that contracts are not essential. But contracts are indeed signed out of the pool for market risk management purposes, which transforms these contracts in financial hedges. So, in this case, these contracts are called “financial contracts” as a counterpoint to the “physical contracts” mentioned in the decentralized market approach. Furthermore, in the centralized market, buyers pay the price that come from the pool, which can be formed by different kinds of mechanisms.

However, as point out by [Barroso *et. al.*, 2005], both market models, though so much different, can coexist: a pool could have bilateral contracts alongside of it and in a bilateral contacts market a voluntary power exchange could be considered.

So, the difference between the decentralized market (or bilateral model) and the centralized market (or pool model) can be deeply associated with the dispatch procedure: while in the decentralized market participants are free to negotiate between them in order to close contracts, and these closed contracts strongly influence the definition of the amount of electricity that will be produced and consumed by each market participant, shaping it as a “self-dispatch”; in the centralized market sellers and buyers submit their bids into the pool, and it is through these bids that it is defined the generation of the producers and the consumption of the consumer, which is summarized as the “central dispatch” of the generation units.

*2.2.1.5 Price formation mechanism: bilateral, tight pool or loose pool*

In the decentralized market approach (or bilateral model), each market participant pays or receives in accordance to their contracts. So, a buyer must pay to the seller the price agreed in the contract, and a seller will be remunerated considering the price of the contract. As previously explained, in this case sellers and buyers will submit notifications to the market operator. So, taking into consideration these notifications, the market operator runs the dispatch that aims to minimize the difference between the contract signed by the agents and the effective generation [Zucarato, 2003]. Therefore, the function of the market operator is to close the balance between load and generation and, if there are congestions in the transmission lines, this problem is solved by modifying the notifications as little as possible [Silva, 2001]. Economic efficiency is achieved given that buyers look for sellers offering the lowest price.

In the centralized market approach (or pool model), the dispatch aims at minimizing the cost of operation of the power system. And to do so, the market operator dispatches the available generators according to the merit order (from the lowest to the highest price bid) until the generation meets the total system load. However, the price formation in the pool model can be divided in two mechanisms: tight pool and loose pool.

In tight pools, only thermal power plants offer prices and quantities, while hydro power plants indicate their availability [Zucarato, 2003][9]. This kind of price formation can be useful for

[9] It seems that this definition just mentions thermal and hydro generation because they are the main kind of source of generation that can be “controlled” in medium and long-term regarding the optimization of the power system. For instance, wind and solar generation cannot store energy as hydro power plants with reservoir can by not

hydrothermal power systems with a large share of hydro generation, like Brazil. With this data, the market operator will minimize the total operation cost considering that the water stored in the reservoirs of the hydro power plants has an opportunity cost linked with the cost of the fuel of the thermal power plants. In this case, it is necessary to run a computational optimization model in order to minimize the expected value of the operating costs over the planning period, and the value of the water can be defined as the variable cost of the most expensive thermal power plant that is necessary to dispatch.

In the loose pool all agents offer prices and quantities to meet a given demand. This procedure is equivalent to use the bids of the participants to build the merit order without the need of a computational optimization model [Zucarato, 2003]. Regarding the price formation, in this case the price can be defined by an uniform price or by the pay-as-bid rules. In the uniform price procedure, as previously mentioned, all sellers receive the same price to every accepted bid, and the payment is done using the market-clearing price, which is defined by the equilibrium between supply and demand. In the pay-as-bid procedure, each seller is remunerated according to his own price bid, and thus the transactions can be priced in a discriminatory manner.

Additionally, as stated in [Barroso *et. al.*, 2005], one of the main advantages of the pool model is that it allows the implementation of the Locational Marginal Pricing (LMP). LMP is based on the marginal cost of supplying the next increment of electric energy demand at a specific location or node. When there is transmission congestion, electricity cannot flow freely to certain locations. In that case, more-expensive electricity is ordered to meet that demand in some locations. As a result, the LMP is higher in those locations [PJM, 2014a]. Thus, nodal prices send clear signals to market players regarding the location of a new generating capacity or transmission lines, but can also allow generators to exercise market power if they are connected at the constrained nodes or areas. Instead of nodal pricing, zonal prices can be adopted. In this case, the congestion between nodes inside a specific zone does not affect the price of that zone.

### 2.2.2 Sequence of markets

The market characteristics discussed above can be combined to design different types of electricity markets to trade both energy and power in order to provide reliability[10] and supply adequacy[11] of the system. This section describes several markets that emerged with the market liberalization: day-ahead, intraday, balancing, forward, future and options markets.

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powering water into the reservoir or thermal generation can by not consuming the fuel. Thus, the market operator should accept all generation available from wind and solar into the dispatch schedule since the non-utilization of this electricity would be a waste.

[10] Reliability is linked with the emphases that a power system should, in the short-term, deliver the energy without interruptions (e.g. network quality is measured is the short-term by the number and the duration of interruptions).

[11] Supply adequacy is connected with the long-term ability of a power system to match demand and supply and with the issue of investment decisions [FSR, 2014a]. In other words, it is the ability to meet demand in the long-term, assuming the regular day to day and season to season fluctuation.

However, when all these markets are operating together it should have a concern related to the imperfect coordination between them. There may be weak links between forward and short-term markets, as well as between the distinct markets for electricity and reserves. Nonetheless, [Wilson, 1999] addresses this issue bringing the idea of "sequence of markets", which means that "a rich sequence of forward markets" (e.g. long-forward, day-ahead, hour-ahead, spot) approximates "a single complete market".

[Willems & Morbee, 2010] note that vertical integration of the electricity production and retail (i.e. vertical integrated company) is an alternative way of creating a "complete" set of hedging instruments between production and retailing. These authors emphasize that markets are incomplete when perfect risk transfers between the agents is impossible. Thus, in practice, markets are never complete since not all risk factors are traded on a market. In addition, welfare in an incomplete market is lower than in a complete market because not all risks are perfectly allocated to the participating agents.

Nevertheless, the approach propose by [Wilson, 1999] solves the problem of market incompleteness relying on the fact that repeated trading of few simple contracts can approximates a complete market to contingent contracts, and that more frequent trading opportunities enhance the completeness of the market. Thus, total welfare can be improved by a sufficient number of additional markets until the market is virtually complete. As noticed by [Hunt, 2002], a fully competitive market requires a "complete market", that is, a full set of forward and short-term markets and risk-management tools for each specific product/time/place.

Finally, as illustrated in Figure 2.7, these types of markets (forward, future, options, day-ahead, intraday and balancing markets) should be seen as a "sequence of markets" in order to address the completeness of the market.

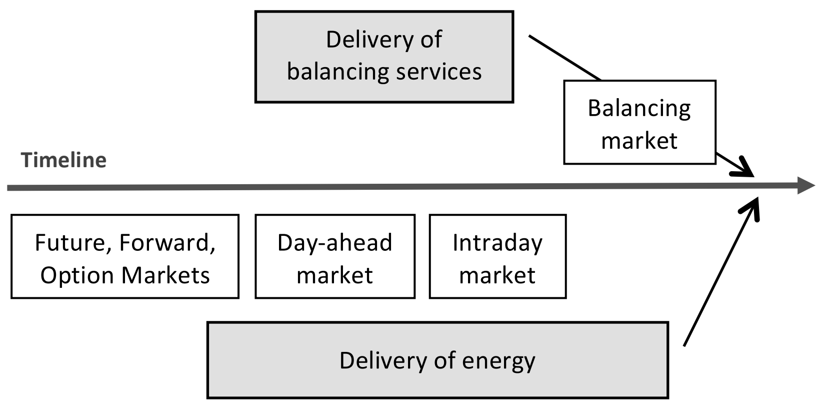


**Figure 2.7 – Sequence of markets**

*2.2.2.1 Day-ahead and intraday markets*

In the day-ahead market, contracts are made between sellers and buyers for the delivery of electricity in the following day [EPEXSPOT, 2014], i.e. the electricity should be delivered on the day after a trade takes place [AEMC, 2014]. Usually, supply and demand submit bids for each hour or each half-hour of the next day.

Nevertheless, corrections closer to the time of production and consumption can be necessary. Therefore, intraday markets aim at managing the adjustments occurring in the generation and demand that may occur after having cleared the day-ahead market [REE, 2014]. This market often uses a shorter time for the exchange of electricity (about 5 to 15 minutes) than the one in the day-ahead market (typically 1 hour) [Booget & Dupont, 2005]. Furthermore, it is expected that these imbalances are non-intentional and are as minimum as possible. So, it can be identified a close correlation between day-ahead, intraday price and price for imbalances.

Additionally, as noticed by [Nord Pool Spot, 2014], as the increase of the share of intermittent renewable sources are connected to power systems such as wind power and PV systems, intraday markets are becoming increasingly important. And the reason is that the unpredictable nature of these sources provokes imbalances between day-ahead contracts and the real generated volumes that often need to be offset in intraday markets.

Thus, prices that come up from these markets are influenced by a combination of factors, including [Karakatsani, 2008]:

- the instantaneous nature of the commodity;
- the shape of the supply function, which, in the presence of diverse plant technologies, is intrinsically steeply increasing and discontinuous;
- the exercise of market power, which results from oligopolistic structures, agents' asymmetries and the negligible demand elasticity to price in the short-term; and
- the substantial agents learning through daily-repeated auctions, but subject to frequent regulatory interventions and market structure changes.

[Huisman *et. al.*, 2007] emphasizes that because of the non-storability of electricity, day-ahead prices exhibit specific characteristics such as seasonality, spikes and a complex time-varying volatile structure. For those producers that didn’t make a previous commitment to deliver electricity at a certain price, there is a chance to benefit from momentarily manipulating that price to a higher level.

Taking into consideration this picture, [Conejo et. at., 2005] states that producers need to forecast market-clearing prices to respond optimally to the pool and to efficiently engage in bilateral contracts. In the short-run, a producer with low capability of altering market-clearing prices (price-taker producer) needs day-ahead price forecasts to optimally self-schedule and to drive its bidding strategy in the pool. In the medium-term, a price-taker producer requires market-clearing price forecasts of several months ahead in order to sign favorable bilateral contracts. Retailers and large consumers need day-ahead price estimates for the same reasons as producers. These price forecasts constitute fundamental information for the retailers to self-schedule and to bid efficiently in the pool, and to engage in profitable bilateral contracts.

Consequently, as stated by [CCEE, 2012a], in most of the electricity markets in the world, the day-ahead price reference is of great importance for the wholesale market. Since day-ahead price is also used for the settlement of future and forward contracts (by indexing long-term contracts), a daily reference is a prerequisite to develop derivative markets.

*2.2.2.2 Balancing market*

Given that electricity is not storable in meaningful quantities, the instantaneous balance between demand and supply is a core concern of system operators. Regarding the physical operation, it is almost inevitable that imbalances occur due to the stochastic nature of the demand, unpredictable plant outages, or fluctuating renewable energy production. Thus, reserves are needed to correct any imbalances in real time and to ensure the security and quality of electricity supply.

As reported by [Zhang & Lo, 2009], in the traditional vertically utilities this service is provided by additional generations (the reserves) from the cheapest to the most expensive available source, and the price to supply the imbalances is already pre-fixed through the bulk supply tariff. With market liberalization, the provision of these reserves has been increasingly organized through market for ancillary services, and these markets are generally entitled reserve markets or balancing markets.

Taking into account the sequence of markets discussed in Section 2.2.2, the balancing market is the last element of this sequence in a sense that it provides the balancing energy to supply the imbalance that was not previously settled by the market players (for instance, in the day-ahead or intraday markets). In other words, the system operator acquires the right to use capacity in the balancing markets in order to perform the second-by-second balancing of demand and supply.

So, in order to have reserves to handle with the random deviations between the energy scheduled and the actual operation, system operators buy the provision of reserves from the market participants (i.e. the system operator contracts various parties for delivery of balancing services such as primary reserve and secondary and tertiary reserves). Thus, in consonance with [Weber, 2010], the balancing markets are asymmetric by design, and this is one fundamental conceptual difference between the balancing markets and the day-ahead and intraday markets. In other words, ancillary services are solely the responsibility of the system operator. Therefore, this entity is the single purchaser party in procuring reserve auctions to meet its reliability obligations [Singh, 1999].

The demand on balancing markets only stems from grid operators, whereas generators are solely acting on the supply side. [Weber, 2010] recalls that this is the first phase of this market, which is named market-based reserve procurement. System operators use the procured reserves to provide balancing in real time as a service to all grid users, and deliver it to all customers simultaneously. This is viewed as the second phase, the reserve use. Then, after the delivery of balancing services, the balancing costs are allocated to the various customers. This is recognized as the third, which is known as the imbalance settlement.

In order to ensure a stable operation of the transmission network, the system operator continually levels imbalances out by maintaining the generated electricity at a constant equilibrium with the electricity consumed. Disturbances in this balance cause a deviation of the frequency of the power system: demand increases or power plant outages will cause the system frequency to decrease; while demand decreases or increase of generation causes the frequency to increase. Additionally, these imbalances in the power system must be avoided in order to prevent damages on consumer devices connected to the network or, even worse, the collapse of the entire system.

As stated in [Weidlich, 2008], frequency control is performed in a three-stage process, which is divided into primary, secondary and tertiary control. The balancing qualities of the three stages differ in terms of the activation method and the response speed. In each stage control, the system operator provides a certain amount of incremental and decremental capacity, which is held by reserve for when deviations occurs. The function of these three control stages is the same: to restore the power balance from those deviations and, consequently, to reestablish the system frequency to its set-point value.

Despite these common points, [Weidlich, 2008] indicates that while primary control needs to be available within a few seconds (up to 30s at latest), the activation of secondary reserve may take several minutes to occur, with a maximum of 5 min. Tertiary control reserve (also denoted as minute reserve) usually comes into action when larger frequency imbalances occurs or to substitute secondary reserve provided by more costly generation. The timeframe in which the tertiary control reserve is scheduled is typically 15 min.

Finally, the generation capacity needed for primary, secondary and tertiary frequency control can be separately procured by specific auctions. The aforementioned author describes the example of the Germany balancing market:

- An Internet-based balancing power market was established by the system operator to acquire the three types of balancing services by single-side auctions. Primary and secondary reserve capacity is procured twice per year for six-month periods, whereas tertiary reserve auctions take place on a daily basis;
- Primary reserve bids consist of the offered quantity (capacity) and of the price asked for the electricity that is actually deployed. In contrast, selling bids for secondary and tertiary reserve contain two price bids[12]: the capacity price (paid for holding the specified generation capacity in reserve, and then lose the opportunity to sell this electricity elsewhere) and the electricity price (paid for the electricity that is actually deployed for balancing purposes)[13];
- Then, the scheme adopted to remunerate successful bids is the pay-as-bid settlement.

In other countries, as in Portugal and Spain, the primary control is a non-paid mandatory service provided by all generators in the market. It is activated on an automatic basis using the speed regulators of each generator. Differently, secondary and tertiary reserves are contracted in specific markets. Secondary reserve bids induce a capacity price and power amount. Part of this amount is considered for up reserve and the rest for down reserve. The service is paid

[12] Several mechanisms are conceivable for selecting successful bids based on two price bids.

[13] One can see reserve capacity as an option, where the exercise value of the option is the price that would be paid for balancing energy. However, an important characteristic of balancing markets, as distinct from financial options, is that reserves are procured not based on any dynamic hedging strategy but based on pre-defined standards [Singh, 1999].

using the capacity term plus the energy that is used inside the band defined by the up and the down values. The tertiary service is paid according to the amount of energy that is used by the system operators.

Apart from the three-stage process for frequency control, the other ancillary services such as black start[14] and voltage/reactive power support[15] are more suitable for procurement through long-term contracts [Singh, 1999]. However, in several countries as in Portugal and Spain these two services are simply considered as mandatory and non-paid.

To sum up, in order to balance the supply and the demand taking into consideration the framework of the market liberalization, several market that impose physical delivery of energy are running: day-ahead, intraday and balancing markets. The balancing markets address, therefore, the fine-tuning between the supply and the demand on a second-by-second basis although different approaches exist in different countries.

*2.2.2.3 Forward and future markets*

While the day-ahead, intraday and balancing markets deal with the delivery of products in the short-term, forward and future markets trade products to be delivered in a specific future date at an agreed price. However, despite forward and future contracts are similar in that they specify an agreed price and future date for delivery of the product, they differ in other terms.

Forward contracts are traded via OTC at a fixed price established on the date at which the contract is originated and with settlement at the time of delivery [Platts, 2014]. Thus, there is no cash paid initially, and the contract price is paid only at the time of delivery, when the asset is received. Any difference between the market value of the product (e.g. the price of electricity in the day-ahead market) and the contract price at the date of delivery represents a profit or loss for the parties involved in the contact [Hunt & Shuttleworth, 1996]. Furthermore, in contrast to futures contracts, forward contracts are tailor-made products rather than standard products, and are not transferable [CME Group, 2014].

Future contracts are generally traded on a power exchange at a price agreed upon at the time of dealing [Platts, 2014], and with continuous settlement of differences between the agreed price and the reference market prices [IEA, 2005]. Therefore, future contracts are highly standardized contracts, and changes of the contract's value are settled in the market on a daily basis. As in the forward contracts, the profit of future contracts corresponds to the difference between the price paid for the contract and the market value of the asset at the maturity date. Nevertheless, when the future contract reaches its maturity date, the holder of the future contract may pay the specified electricity price to the issuer of the contract in return for the

[14] Black Start is the ability of a generating unit to go from a shutdown condition to an operating condition, and start delivering power without assistance from the power system [NYISO, 2014].

[15] Voltage Support Service is the ability to produce or absorb reactive power and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions subject to the limitations of the resource's stated reactive capability [NYISO, 2014].

product, or sell the contract immediately prior to its maturity whereas the issuer buys back it to offset his obligations [Hunt & Shuttleworth, 1996]. Moreover, futures contracts deal with relatively short-term transactions (1-3 months) if compared to forward contracts [Nakamura *et. al.*, 2006].

While forward contracts can be customized to suit the specific needs of the two involved counterparties, the future contracts add liquidity to the market since they enhance the ability of the market to facilitate a product being sold quickly. So, various forms of forward and future contracts are widely used in electricity markets to manage financial risks associated with volatile market prices. These contracts enable generators to hedge unfavorable low market prices and retailers to hedge financial losses due to high market prices [Anderson, 2008].

Forward contracts are also one way of mitigating the market power of generators. Concerns over the exercise of market power have led regulators to force forward contract commitments on the producers. Despite these contracts have taken various forms, they all have one important feature in common: they commit producers to receive a fixed price for a certain fraction of their output before wholesale market competition takes place [Frutos & Fabra, 2012].

Besides the market power, there are other concerns that can be enhanced by forward contracts, such as risk and investment. [Ausubel & Cramton, 2010] defend the thesis that the goals of electricity market design are better met when the short-term market is complemented with two forward markets, one medium-term and one long-term. They start underlining that a well-designed short-term market is necessary for efficiency, but is not sufficient since efficiency requires addressing issues regarding risk, investment and market power.

Then, it is demonstrated that in the medium-term (1-3 years) a forward market lets suppliers and demanders lock electricity prices and quantities. Thus, this measure limits the exposure to fluctuations of the short-term price (i.e. it addresses the market risk) and mitigates the incentive to distort bids (i.e. it addresses the market power). In long-term, a forward reliability market assures that adequate resources are available when they are needed (i.e. it addresses the security of supply). So, forward markets: reduce risk for both sides of the market, since they reduce the quantity of energy trades at the short-term price; prevent market power because suppliers are in roughly balanced positions when they enter in the short-term market and, thus, their behavior in this market is likely less extreme; and coordinate investment in new resources, assuring the supply adequacy.

*2.2.2.4 Options market*

In deregulated electricity markets, both consumers and producers of electricity can better manage their risk by hedging using not only forward and future contracts but also other financial derivatives such as options [Nakamura *et. al.*, 2006]. The extent to which a firm can hedge its performance to market changes evolve from pure OTC to more complete markets in which there is a liquid trade of a broad set of derivatives [Willems & Morbee, 2010]. In order to enhance the completeness of the market, apart from the forward and future markets, it can also be added a set of option markets with different strike prices.

Intraday, day-ahead, forward and futures contracts are all agreements to deliver a fixed quantity at a defined time in the future. However, since many traders prefer to retain a degree of flexibility to future deliveries, the option contracts allow for a trader to decide whether or not the electricity should be delivery at a later date [Hunt & Shuttleworth, 1996]. Unlike a forward or future contract, an option contract does not oblige the holder to buy the asset.

According to [IEA, 2005], this notion of "value of optionality" (i.e. the felling that an option of postponing an action has a value) is becoming more and more recognized in many risky business environments, including electricity markets. This author observes that it is valuable: for the trader who owns a future contract to be able to postpone the decision to sell the contract until he knows how the price will behavior; for the investor to build a new power plant in small steps, once he can be able to wait until the option is called or the project is financially a viable investment; and for a consumer to have some time to consider a new contract offer. Finally, markets for options standardize these risks since they establish standard terms and conditions.

Having that said, the option market works as follows. A "call option" gives the holder (e.g. the consumer) the right to buy the asset (electricity) at a specified price at some time in the future[16]. This specified price is the "exercise price" (or "strike price"), i.e. it is the price paid when the option is exercised (when the holder call for the contract to be fulfilled). In order to obtain the option, the holder of the option contract (the buyer) must pay a "fixed premium" (or "option fee") to the issuer of the option contract (the seller) [Hunt & Shuttleworth, 1996].

In the electricity industry, there is the risk of a generator running a number of hours less than the required to recover his fixed cost. This can happen because he will be out of the merit order (then not dispatched) when the power plant variable cost is above the market price. In order to deal with the foregoing quantity risk (i.e. the unpredictable pattern of the power plant output) the option contract can be used by providing protection against this situation. In such case:

- The exercise price (or strike price) can be view as equivalent to the variable cost of the power plant (cost per KWh produced), and the holder can call options in order to dispatch the power plant when the market price is above the exercise price; and
- The fixed premium (or option fee), which is the price to purchase the option contract, can correspond to the fixed cost of the power plant (cost per installed kW), and the issuer can sell options in order to support investment in new generation capacity.

By doing so, the generator is demanding (and customer is willing to pay) a fixed revenue to recover the power plant investment, and the revenues obtained when the option contract is exercised will recover the generator's variable cost for running the power plant. Thus, this

[16] In other hand, a "put option" gives the holder (e.g. the producer) the right to sell the asset (electricity) at a specified exercise price at some time in the future.

mechanism (further discussed in Section 2.3.2 as a capacity remuneration mechanism) turns the construction of the power plants more attractive to the investors.

As can be noticed, this approach is comparable with the PPA contracts (addressed in Section 2.1.2) in the sense that signing of a PPA in advance helps the entrepreneurs with the financial modeling related to the construction of the project. In addition, these long-term contracts have clauses that contain an explicit “availability payment” (or “capacity payment”) to recover the fixed cost, and an “energy payment” to recover the variable cost when the power plant is running. However, the option contracts cover risks and foster efficiency in a different way: through medium-term contracting (instead of long-term contracting) that takes place in a shorter time interval.

[Vazquez *et. al.*, 2002] report that in an organized market where reliability contracts based on financial call options are auctioned, both the total amount of money to be pay to the generators (in exchange for their availability) and its allocation among the different power plants are determined through competitive mechanism. This results in a stabilization of the income of the generators and provides a clear incentive for new generation investment, with a minimum of regulatory intervention.

Indeed, a call option is an insurance against energy supply shortfalls, which can be physically or financially exercised. Physical exercise entails delivery of the contracted energy by the counterparty (by scheduling as a bilateral contract), and financial exercise entails a financial settlement where the counterparty pays to the holder the difference between the market price and the strike price for the contracted amount [Oren, 2005].

This hedging instrument can be applied by using different schemes of call options. [Vazquez *et. al.*, 2002] propose to establish an organized and mandatory market where call option contracts are traded via auctions with a high strike price and explicit penalty for non-delivery of energy. The procedure of this mechanism is the following:

- Initially, the regulator sets the basic parameters: i) strike price; ii) total amount of options to be bought, Q, which depends on the expected demand and on the adopted reliability criteria; iii) value of the explicit penalty; and iv) time horizon of the auction;
- The generators submit their bids (each of them is a pair of price and quantity) to the auction. The quantity in the bid expresses the capacity that the generator is willing to commit, while the price represents the option fee. Bids are valid for every hour in the considered period;
- Bids are ordered according to their price (option fee) and the lowest ones are selected until the sum of all the accepted quantities equals the prescribed quantity Q. The price of the last accepted bid determines the option fee P that is paid to all the accepted generators;
- A generator with an accepted bid of q receives a fixed premium of $q_x P$. The option fee P is paid on day-by-day basis in order to avoid any distortion associated to cash flow;
- In order to strengthen the incentive to be available during the critical periods when the short-term price is higher than the strike price, it is proposed to add in the option

contract an explicit obligation associated to the physical delivery of the committed capacity: the additional penalty; and

- The buyer of the option receives from the seller, for each MW purchased under the option contract, any positive difference between the short-term price and the strike price. This is true for every hour within the time horizon for which the option is defined to be active.

So, in practice, the call option is acting as a price cap which limits, at a maximum value of the strike price, the price consumers are paying in the short-term market. This can be interpreted as if the consumer had the right to buy at the strike price when the short-term price is lower than the strike price, but he decides not to exercise his right and buys directly in the short-term market. When the short-term price is higher than the strike price, he uses his option and buys electricity at the strike price. From the generator's point of view, selling an option means that the generator will receive an amount of money for renouncing the opportunity of selling electricity at the short-term price when this price is really high (i.e. higher than the strike price).

## 2.3 From market results to the physical operation of the power system

This section discusses the intersection between the operation of the power system conducted by the system operator (ISO – Independent System Operator or TSO – Transmission System Operator), especially regarding the dispatch schedule procedure, and the electricity market, particularly concerning the commercial commitments and investment of the market participants. In other words, the analysis in this section focuses on:

- How is the meet between the physical dispatch (that is designed to achieve the minimal operational cost in each account period, as it occurs in the centralized market, or to minimize the difference between the contracts signed and the effective generation, in the decentralized market) and the commercial commitment of the market participants and their decision-making process for investment in new capacities.

Regarding only the physical operation, concerns related to the performance of the power system can be address by the evaluation of the power grid stability. These concerns deal with quality indicators which refer to technical phenomena such as variations in frequency, short-duration and long-duration voltage variations, transients and waveform distortion [FSR, 2014b]. In addition, the network reliability can be measured by the number and the duration of interruptions together with the power that is affected by each of these events.

Nevertheless, in order to analyse the frontier between the physical operation and the market design, other quality aspects should be highlighted, such as:

- **Market design completeness in the short-term**: It relies on the connection between the commercial commitments of the market participants and their capacity to deliver the contracts through their own generation. In this sense, it can be expected a smooth combination between the dispatch schedule procedure executed by the market operator and the ability of the market design to allow the agent to take part on the construction of the merit order. Thereby, this analysis is connected with a short-term perspective since it compares the closed contracts, the schedule production and the real production values;

- **Market design adequacy in the long-term**: It refers to the ability of the market to ensure sufficient capacity to meet the demand in the future. Generation companies will only invest in new power plants if they expect that all their costs (both variable and fixed costs) will be totally recovered in the end. Thus, the dispatch schedule and the market price formation[17] will also influence the investment decisions and the guarantee that, in a long-term perspective, there will be investment commitments and the maximum peak demand will be meet by the total installed capacity.

So, just as it is important to have quality in physical operation of the power system, it is also crucial to have quality regarding the market design of the electricity sector. The market design completeness in the short-term is discussed in Section 2.3.1, while the market design adequacy in the long-term is discussed in Section 2.3.2.

Apart from the imbalances discussed in the balancing market (Section 2.2.2.2), which are inevitable to happen due the unpredictable nature of events such as the stochastic demand pattern, power system equipment unexpected failures and volatility of renewable energy production, because of the incompleteness and failures of market designs it may occur: exposure to the imbalance price due the absence of flexibility to enable agents to endure their contracted positions through their own generation (Section 2.3.1); and lack of investment in the system expansion due the absence of generators' interest (Section 2.3.2).

Moreover, while the unpredictable "energy imbalances" can cause loss of stability of the power grid, the above-mentioned "exposed position" and "lack of investments" can undermine or destabilize the electricity market. In order to clarify these issues, equations 2.3, 2.4 and 2.5 expresses the energy imbalances, exposed positions and lack of investments.

$$\textbf{Energy imbalance} = (real\ production) - (schedule\ production) \tag{2.3}$$

$$\textbf{Exposed position} = (real\ production) - (contracted\ energy) \tag{2.4}$$

$$\textbf{Lack of investment} \sim (total\ installed\ capacity) - (maximum\ demand) \tag{2.5}$$

### 2.3.1 Market design completeness in the short-term: How is obtained the conciliation between the dispatch schedule and the commercial commitments?

The difference between the electricity imbalance and the exposed position is also represented in Figure 2.8, where a chain of events (ex-ante closed contracts, scheduled production and real production) will influence their values.

In order to clarify these expressions, it must be said that:

[17] Prices coming from the short-term market remunerate the running cost of the power plant can be also used to compensate the investment.

- Closed contract is a commercial commitment where no clause can be modified without mutual consent. In the present case, it comes from the electricity trade in which a generator is committed beforehand (ex-ante) to deliver a certain amount of electricity;
- Scheduled production is the unit commitment, and it comes from the dispatch schedule;
- Real production is the electricity measurement of effective generation.

The emphasis here is in the generation side, but the analysis regarding the energy imbalance and exposed position can be applied equally to the consumption side.

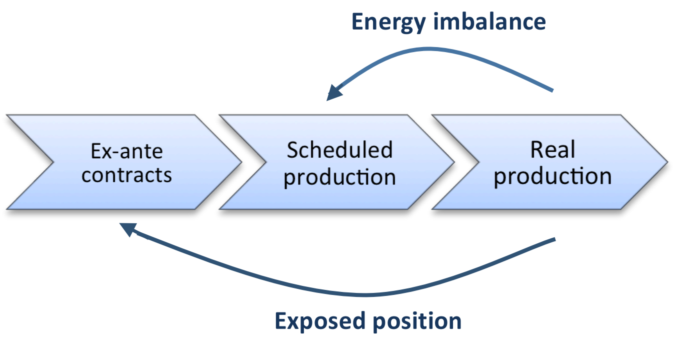


**Figure 2.8 – Energy imbalance and exposed position**

The Figure 2.9 shows again the successive steps, but now with the explicit case of a day-ahead market (DA) and intraday market (ID). The DA and ID ex-ante contracts set the scheduled production, and in the last step the electricity is measured to compute the real production.

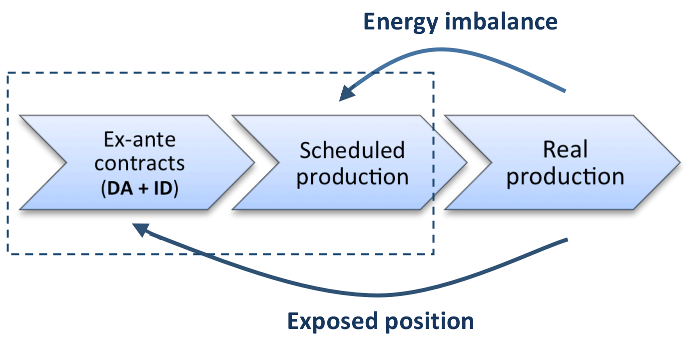


**Figure 2.9 – Energy imbalance and exposed position: with DA and ID markets**

As it can be observe in Figures 2.9 and 2.10, when there are day-ahead and intraday markets, the market participants are active in the dispatch procedure, and generators have the possibility to repetitively adjust their bids and thus avoid energy imbalances and exposed positions. In this case, since the commercial committed that comes from the DA and ID markets strongly influence the scheduled production, the energy imbalance can be equal to the exposed position. Small unintentional imbalances can still occur, and then they are settled considering the imbalance price. Moreover, in some case penalties for those participants that were responsible for these imbalances.

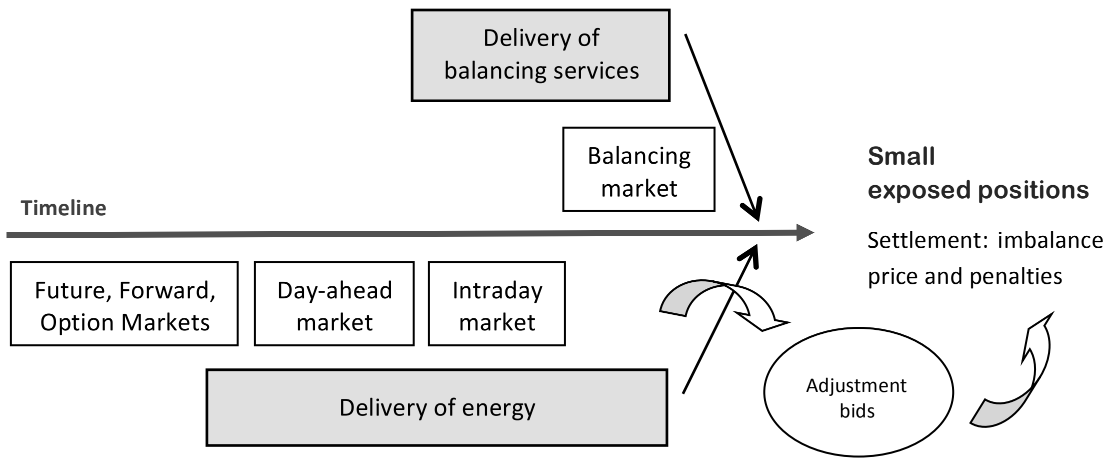


**Figure 2.10 – Sequence of markets: small unintentional energy imbalances**

When there is no mechanism such day-ahead and intraday markets, market participants can be active in order to comply with their contracted positions. Nonetheless, when long-term contracts are concluded, and the scheduled production takes place without considering these commercial commitments, large differences between the energy imbalance and the exposed position are likely to occur. This can happen because, in this case, these closed contracts cannot influence the schedule production. This is illustrated in Figure 2.11.

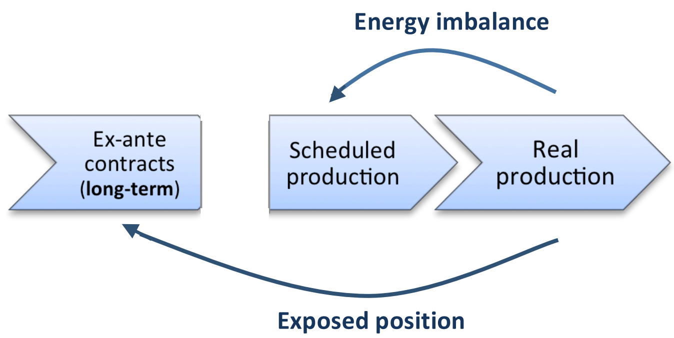


**Figure 2.11 – Energy imbalance and exposed position: without DA and ID markets**

So, in this situation participants will probably have significant unintentional exposed positions. In Figure 2.12 this is exemplified with a week-ahead dispatch schedule, which is the Brazilian case[18]. Furthermore, in the Brazil generators are allowed to set once a year the monthly amount of the long-term contracts. In other words, generators are committed through long and medium-term contracts, and are allowed to, once a year, distribute within each month the energy of the contract (i.e. the energy committed through contracts are split by months). This is called in Brazil the "seasonalization of the contracted energy".

[18] In Brazil, the optimization of the central dispatch relies on weekly scheduling adjusted on a daily basis.

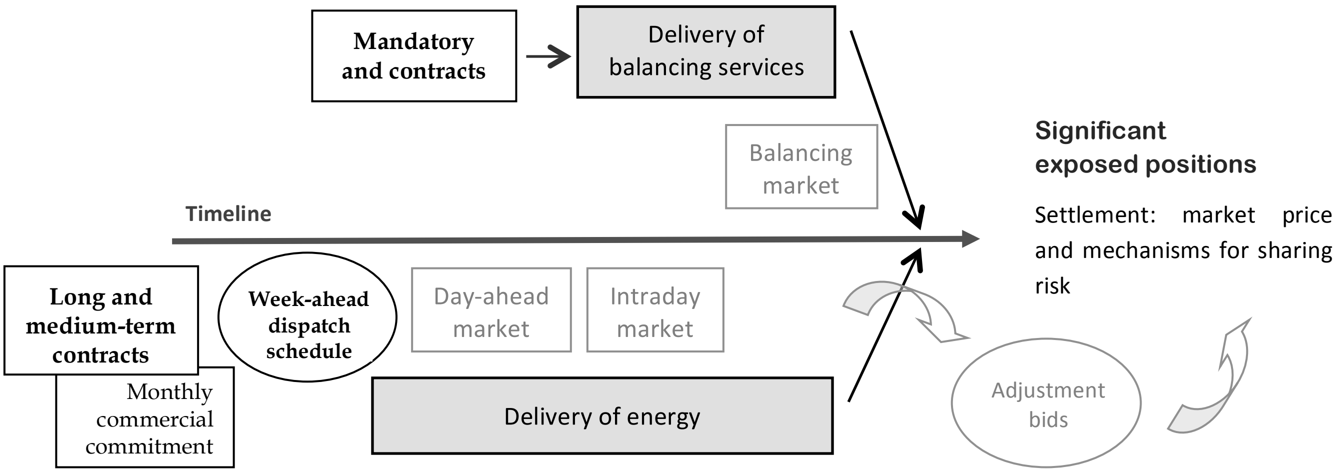


**Figure 2.12 – Sequence of markets: likely to have significant unintentional exposed positions**

This exposed position occurs due the fact that participants couldn't meet their contracted position because the market design doesn't allow it. The settlement of the exposed positions is, therefore, a risk for generators given that they would have to buy electricity from the short-term market at the volatile market price in order to delivery their commercial commitments.

Therefore, some mechanism for sharing this risk can be implemented, and this is what happens in Brazil. The mechanism designed particularly to share this kind of risk is translated in rules that run in the settlement process and are applied automatically to all market participants. As a result, this is not endowed with flexibility in a sense that generators cannot deal with it in order to consider their own strategy and risk perception. This mechanism is known in Brazil as Mechanism for Reallocation of Energy (*MRE*), and it is discussed in detail in Chapter 3, Sections 3.2.4 and 3.3.3.

Finally, Table 2.1 presents some elements of the market previously discussed in order to bring a slightly broader outlook on the problem. This table intends to examine the conciliation between the market designs, considering some markets and their elements, and the physical operation of the power system, in particular with the dispatch schedule. Thus, it addresses the divergences that can exist between the ISO/TSO duties and the market participants commercial commitments. Moreover, this table focuses on markets for electricity-related commodity and ancillary services, and the last column does not include taxes or subsidies that usually compose the tariff of the final consumers.

Model 1 doesn't deal with contracts since this industry structure is related to the command and control management of a vertically integrated company. So, the ISO/TSO a priori knows the generation cost and he dispatches the power plants considering the minimal operational cost. There is no need for conciliation once there is no contract involved, and the consumers pay for each MWh produced based on the cost of service.

In the Brazilian case, which contains Model 2 coexisting with Model 4, generators are not active in the central-dispatch procedure and the ISO/TSO dispatches the power plants without considering the quantity committed through the long-term contracts. Generators have no alternatives to manage their contracted positions, and thus they can be exposed to the risk of purchasing electricity in the short-term market if not dispatched to generate enough to meet their commercial commitments.

**Table 2.1 – Conciliation between physical dispatch and commercial commitments**

| Electricity industry structures | Contracts between market participants | System operator dispatch | Conciliation between dispatch schedule and contracted positions | Costs/prices passed on to tariff end consumers |
|---|---|---|---|---|
| **Model 1**<br><br>**Vertically integrated utility** | Without contracts (command and control management) | System operator dispatches considering the minimal operational cost, since it a priori knows each marginal cost. | There aren't electricity market and contracts involved, so there isn't need for conciliation. | Consumers pay for the cost of each MWh produced based on cost of service regulation. |
| **Models 2 and 4**<br><br>**Single buyer model coexisting with a retail competition**<br><br>(Brazilian case) | • Long-term physical contracts (PPA) via public auctions<br>• Ancillary services are provided by grid codes and by contracting for reactive energy<br>• Medium-term physical contracts | • Minimization of the operation cost through the tight pool approach.<br>ISO doesn't consider the amount of electricity sold or bought through contracts (it just uses the price from the public auction to perform the merit order). Generators are not active in this central-dispatch procedure. | It is expected that participants comply with their contracts by their production. However, ISO decides their outputs without considering it. For PPAs with only quantity payment (usually hydros) it is needed a mechanism to share the associated risk. For PPAs with both energy and availability payment, there is no risk of not being dispatched. | • Prices coming from PPAs;<br><br>PS: Market participants settle imbalances. |
| **Models 3 and 4**<br><br>**Wholesale and retail competition**<br><br>(like Texas in 2000) | • Bilateral physical contracts<br>• Balancing market<br>• Medium-term financial contracts | • Minimization of the difference between the closed contract and the real production.<br>In short-term, generators submit notifications to the ISO/TSO, which are expected to be equal to contracted positions. ISO/TSO dispatches considering these notifications. Generators are active through a self-dispatch procedure. | ISO/TSO tries to dispatch the exact amount of the physical notifications, i.e. his goal is to minimize the suppliers' exposed position. | • Prices coming from bilateral contracts and balancing market;<br><br>PS: Market participants settle imbalances. |
| **Models 3 and 4**<br><br>**Wholesale and retail competition**<br><br>(like some USA states, and European countries) | • Short-term physical contracts markets, as day-ahead and intraday<br>• Balancing market<br>• Medium-term financial and physical contracts | • Minimization of the operation cost through the loose pool approach.<br>Sellers and buyers submit their bids. Power Exchange dispatches considering the successful bids. Generators influence, through their bids, the dispatch schedule. | ISO/TSO implements technical adjustments to enforce violated constraints. | • Prices coming from the short-term market and balancing market;<br><br>PS: Market participants settle imbalances. |

Consequently, what happens in Brazil is that, although the trades are made by long-term contracts (PPA), for the case of Regulated Contracting Environment – *ACR*, or by medium-term contracts usually via OTC, as occurs in the Free Contracting Environment – *ACL* (both "contracting environment" are discussed in Chapter 3), it is inevitable that the amount contracted will not match the amount actually generated. This explain the adoption of the aforementioned *MRE*.

Regarding Model 3, Table 2.1 includes two examples: one regarding the decentralized market (bilateral model); and other one related to the centralized market (pool model). The difference relies in the fact that in the former generators first close bilateral contracts, then they submit physical notifications to the ISO/TSO, and the ISO/TSO works to minimize the difference between these notifications and the real generation. In the pool model, generators submit bids into the power exchange, and the dispatch of the ISO/TSO aims to minimize the operation cost, which is done by dispatching the generators that had successful bids. However, in both cases generators influence the dispatch procedure, through a self-dispatch procedure or through their bids into the short-term market.

Regarding the decentralized market, the Texas case in the year 2000 is the example presented in the table. Rather than adopting a pool based wholesale market, Texas adopted an approach designed to rely on bilateral trades [Joskow, 2008]. Prior to 2001-2002, the Texas wholesale market was designed to foster bilateral contracts between the generation companies and the retail suppliers in order to reduce consumer exposure to hour-to-hour fluctuations of electricity prices. In this market design, the ISO does not operate a centralized short-term market for electricity, but he does operate a balancing market with some similar attributes [Zarnikau, 2005].

Instead of the centralized market, the ISO required to the Qualified Scheduling Entities (QSEs) to submit ''balanced schedules'' on a day-ahead basis to ensure that these entities had arranged for sufficient generation resources and ancillary services to meet the expected demand they had committed to serve [Zarnikau, 2005]. In the end of 2002, balance schedule requirements were relaxed aiming to encourage the establishment of a private short-term market for electricity. The purpose was, through a short-term market, to improve price signals and transparency, encourage demand side response, and foster more efficient use of available system resources.

Regarding Models 3 and 4 running as a centralized market, the information presented in Table 2.1 was inspired in some USA's states and European countries. [Imran & Kockar, 2014] reveals that the majority of the ISO in the USA[19] are adopting or they can be expected to adopt in the future the standard market model issued by FERC (Federal Energy Regulatory Commission) in 2003, which is named Wholesale Power Market Platform (WPMP). The WPMP consists of

[19] Examples of the ISO in USA: California ISO (CAISO), Electricity Reliability Council of Texas (ERCOT), Mid-west Independent System Operator (MISO) Pennsylvania-Jersey-Maryland Interconnection (PJM), New York ISO (NYISO), and ISO New England (ISONE).

centralized energy markets (such as day-ahead market and a real-time market[20]), balancing market for ancillary services, financial transmission rights market, and some mechanisms such as capacity markets to ensure supply adequacy.

Beside the price-sensitive bids that are submitted to the market operator in the centralized market that follows the WPMP, it is possible for the generators to self-schedule their generation. This self-scheduling is used to support bilateral trades, both financial (essentially Contracts for Difference – CfD[21]) and physical ones. This is done by separately submitting self-schedule bids to the market operator, then it is run the pool clearing algorithm which automatically accepts self-schedules subject to transmission constraints and then issues the final schedule including feasible self-schedule.

In Europe, the European Regulator's Group for Electricity and Gas (ERGEG) launched in 2006 the Electricity Regional Initiatives (ERI), which were designed with the ultimate goal of implementing a pan-European electricity market called Electricity Market Target Model (EMTM) [Imran & Kockar, 2014]. With similarities in relation with the WPMP designed by FERC, this emerging design for the European market consists of four basic components: forward market, day-ahead market, intra-day market and balancing market. Besides that, capacity mechanisms are also a concern among European countries.

In addition, some nuances can be found when comparing the market design named WPMP (FERC's proposal) with that one called EMTM (ERGEG's proposal), and these differences are presented in Table 2.2. Nonetheless, in both WPMP and EMTM proposals there is a smoothly conciliation between dispatch schedule and commercial commitments. If comparing the features of the decentralized and centralized markets (Model 3 and Model 4) with the Brazilian case (Model 2), we note that the risk of exposition is likely to be higher in Brazil. This indicates that the completeness of the market design is addressed more adequately in the former than in the latter market design.

In markets as day-ahead, intraday and balancing markets, players are more active in the definition of the merit order on day-by-day basis and so they have more opportunities to cover their positions engaged by bilateral contracts. This fact can be viewed as a higher completeness of the market when compared with a market where participants close their position by long-term contracts.

[20] While the day-ahead market can determine the LMP base on the Optimal Power Flow (OPF) solution given bids, demand forecast, generation constraints and flow limits, which doesn't depend on the actual system operation, in the real-time market an ex-post formulation is used to calculate the real-time LMP by solving an incremental OPF [Jia et. al., 2012]. For example, the PJM's Real-Time Market can be seen as a spot market in which current LMPs are calculated at five-minute intervals based on actual grid operating conditions [PJM, 2014b].

[21] Contracts for Difference are bilateral contracts settled by handing over the net cash value of the item sold rather than by handing over the item itself, and it is applied in the electricity markets as following [Hunt, 2002]: (i) when the short-term price is below the contract price, the consumer pay the difference between the contract price and the short-term price to the generator; (ii) when the short-term price is above the contract price, the generator pay the difference between the short-term price and the contract price to the consumer.

**Table 2.2 – Some difference between Europe and USA [Imran & Kockar, 2014]**

| Comparison aspects | USA<br>WPMP proposed by FERC | Europe<br>EMTM proposal by ERGEG |
|---|---|---|
| Volume of the day- ahead market and forward bilateral trade | More bilateral trade and less day-ahead market | More bilateral trade and less day-ahead market |
| Generator hourly bids in day-ahead market | Cost-based multi-part bids containing fuel cost and start-up cost | Price-based single-part bids containing price and energy volume |
| Generator data with bids for day-ahead market | Detailed generator data including operating and ramp limits and minimum up and down times | Operating limits are implicit in the bid. No ramp limits or minimum up and down times are provided |
| Generator block bids | No block bids | Multi-hour block bids |
| Generator scheduling | Partially self-scheduling with centralized unit commitment | Fully self-scheduling without centralized unit commitment |
| Zonal/nodal pricing | Nodal pricing called locational marginal price (LMP) | Zonal pricing called market clearing price (MCP) |

### 2.3.2 Market design adequacy in the long-term: How does the short-term market allocate feasible technologies in order to add new capacities?

Once addressed the market design considering a short-term perspective in order to analyze the completeness of the market design, it will now be addressed the supply adequacy, i.e. the ability of a power system to match demand and supply taking into consideration the investment decisions of the market participants. Moreover, this issue is related to the decision-making process of participants in a long-term perspective. To do so, it is also necessary to have in mind the price formation mechanism, the dispatch procedure, and particularly the inherent investment cost of the power plants.

Thinking about the market liberalization and the restructuring of the electricity sector, especially the move from Model 1 to Model 2, 3 or 4, the connection between the market design and the physical operation of the power plants is relevant because, as mentioned in Section 2.1.3, the private capital will be largely responsible for the expansion of the power system[22]. Entrepreneurs will only invest in new power plants if they expect that their costs will be recovered, and the capital invested will be adequately remunerated. Therefore, there is a strong coupling between the short-term market and the supply adequacy of the power system

[22] To recapitulate, liberalized markets create a new investment paradigm in which decisions are taken under competitive pressure. In consequence, Models 3 and 4 will break up the centralized decision-making process that is typical of Models 1 and 2, switching it to a decentralized process (Models 3 and 4) where market players take decisions considering the market signals.

since there are consequences from the short term dispatch of the power plants on the market performance in long run.

In the end, one wants to avoid the "lack of investment" (already mentioned in Section 2.3, equation 2.5). Thus, the analysis of this section focuses on the following questions: Are there in the market design enough incentives to provide adequate investment? Will the response of generators regarding the short-term prices come in the form of new facilities? Should a capacity mechanism be added to the market design?

Let's start supposing that generators should sell their electricity only through the short-term market. This scenario corresponds to the case of Models 3 and 4 admitting that participants trade in a centralized market only via a power exchange in a day-ahead market. As already mentioned, in this condition competition continuously occurs on a day-by-day basis. In addition, it is assumed that the price formation mechanism is the loose pool (all agents submit bids under the form of pairs of prices and quantities), and the market operator, aiming to minimize the operation cost, will dispatch the generating units in order of their prices bid from the lower to the higher one until the demand is met. Finally, in order to remunerate the successful bids, it can be chosen either the pay-as-bid or the uniform price settlement procedures. Lastly, for the time being let's assume that this market design adopts the uniform price procedure.

To support this analysis, it is useful to address the cost structure of the generation, i.e. the Total Cost (TC), Fixed Cost (FC), Variable Cost (VC) and Marginal Cost (MgC). The fixed cost does not depend on the production volumes, and consists of depreciation charges, lease payments, insurance premiums, interest on loans, wages of the permanent staff, and some other expenditures; while the variable cost, on contrary, vary with the change in the production volumes, and consists of expenditures on material, fuel, a certain part of labor and similar variable resources [Belyaev, 2011].

In particular, average-cost data are more meaningful for making comparisons with product price, which is always calculated on a per-unit basis. Moreover, a company decision regarding what should be the level of production is typically a marginal decision. Thus, the marginal cost, which is defined as the additional cost in producing one more unit of the output, is also a crucial concept. As explained by [McConnel *et. al.*, 2009], marginal cost designates either the cost incurred in producing the last unit of output or the cost that can be "saved" by not producing that last unit.

Finally, the relationships between the ATC (Average total Cost), AFC (Average Fixed Cost), AVC (Average Variable Cost) and the MgC are presented in Figure 2.13. Regarding the mathematic formulation, the ATC is equal to the sum of the average fixed and variable costs (ATC = AFC + AVC), that is for a specified quantity q the corresponding ATC is the sum of AFC and AVC obtained for q. On the other hand, MgC is given by the derivative of the total cost function with respect to the quantity q (MgC = $d$TC/$d$q).

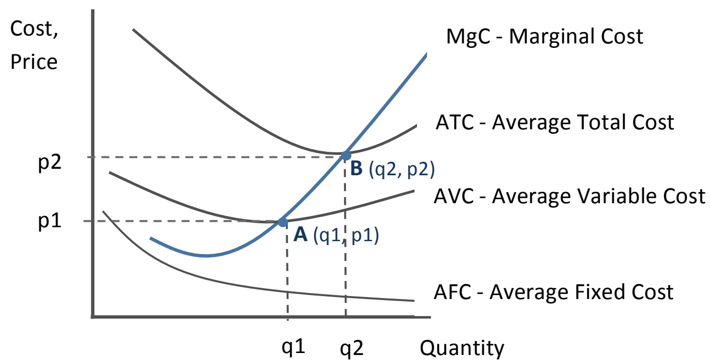


**Figure 2.13 – Relationship between AFC, AVC, ATC and MgC [McConnel *et. al.*, 2009]**

Concerning the decision to shut down a power plant or to produce electricity in this market design, as shown by [Belyaev, 2011], generator face the following situation:

A. At the market price that is below the value at point A, that is below p1, the power plant cannot recover even its variable cost, and thus the generator should shut down the power plant;
B. At the market price between the values at point A and point B, that is between p1 and p2, the power plant recovers its variable cost, but the fixed cost is incompletely recovered, and then the power plant cannot operate for long;
C. At the market price equal to the value at point B, that is p2, it is profitable for the power plant to produce the corresponding quantity, and in this case it will fully recover the ATC, including the normal profit;
D. At the market price above the value at point B, that is above p2, the generator will start gaining an additional profit, the so-called "economic profit". This profit per unit is equal to the difference between the market price p and the average total cost.

Consequently, it is supposed that generators will bid a pair of price and quantity equal to the value at point A (MgC crossing AVC), if they expect that their fixed cost will be recovered somehow[23], or at least equal to values at point B (MgC crossing ATC), if they are trying to recover both the variable and fixed costs in the short-term market. So, the question from now on is: how can the fixed cost be recovered in this example of market design[24]?

First of all, it must be said that some energy market supporters indicate that revenues generated during peak load periods are adequate to attract investment [Finon & Pignon, 2008]. This reasoning postulates that sometimes market prices will reach extremely high levels (very far from the value at point B), and then generators will have an "additional rent" to also recover the fixed cost.

[23] The approaches that have been employed to deal with this alternative will be discussed below, when addressing the "additional rent" and "capacity mechanisms".

[24] To refresh, this example corresponding to the scenario characterized by Models 3 and 4 with a centralized market like a day-ahead, loose pool price formation mechanism and uniform price procedure.

Considering the example of the short-term market described above, it is now assumed that the market contains participants that own several types of power plants from different technologies. Power plants of diverse types differ in their mix of costs (fixed and variable), not to mention operating conditions and other issues. Considering the postulate stated in the previous paragraph, these agents will submit bids to recover the AVC (point A), and wait that the short-term price reaches higher values. During these periods, since an uniform price procedure is adopted, they will recover the fixed cost through this an additional rent. Figure 2.14 illustrates a case of the resulting merit order during a peak load.

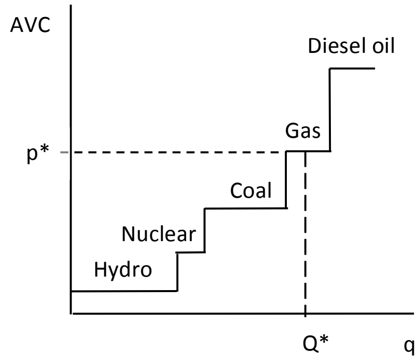


**Figure 2.14 – Typical merit order and AVCs for diverse types of power plants**

In this Figure, Q* is the market demand and p* is the clearing price. As can be noticed, hydro, nuclear and coal stations receive the AVC of the gas power plants (last resource dispatched to meet the demand), which is higher than their own AVC. Thereby, hydro, nuclear and coal power plants capture the additional rent indicated, and they will use it recover the FC. In this case, this additional rent represents the “producer surplus” discussed in the Section 2.1.3 and shown in Figure 2.4.

In the long run, according to the classical economic theory, the market will reach an equilibrium, and then the mix of technologies will be chosen by the market itself: i) power plants with high VC (usually with low FC) will analyze how many hours they expect to be dispatched due to the peak load, and they will enter into this market if the sum of the estimate revenue will recover their both FC and VC; ii) power plants with low VC (usually with high FC) will enter into this market if they expect that additional rents coming from peak load periods will also recover their FC.

Now, still considering the example presented in this section, instead of the uniform price let’s assume that the pay-as-bid procedure is adopted. In this case, if there is no alternative way to recover the FC apart from the short-term price, participants will bid to recover both the FC and VC, and thus, from the perspective of the short-term market, the vertical axis of Figure 2.14 will have ATC instead of AVC.

However, if it is adopted the pay-as-bid procedure, there will be a concern related to the possibility of generators cheat: participants have not stimulus to submit bids according to their own costs; rather than that, they will try to submit price bids that are closer to the price bid of the last unit that it is supposed to be dispatched.

In addition, if later on the market price p* is so high and above the point B during so many periods that it will give to some generators an "economic profit", then more of these generators will enter into this market, and the market in long run will reach a new equilibrium. This process is illustrated in Figure 2.15 through the following steps: first some power plants are implemented because they are attracted by the economic profit (in this example: hydro, nuclear and coal); thus, the supply curve shifts to the right (from S1 to S2); and then the market price decreases from $p_1$* to $p_2$* (in this illustration the demand curve D remains the same).

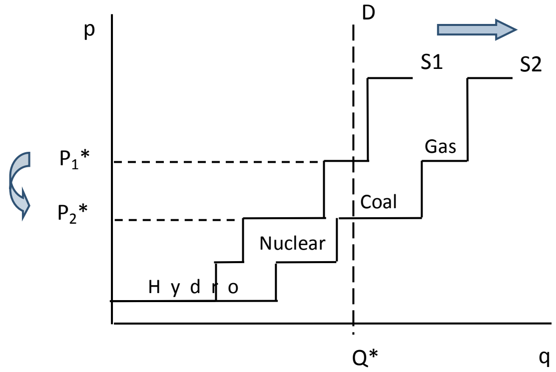


**Figure 2.15 – Shift of the supply curve from S1 to S2**

In the end, this is how the short-term market provides by itself the expansion of the system and addresses the supply adequacy: generators will invest in new power plants if they expect that their cost (FC and VC) will be recovered; if uniform price is adopted, they will recover the FC through the additional rent obtained during the peak loads; if pay-as-bid is adopted, their bids will include both FC and VC; and the market will choose the mix of technologies.

Nevertheless, the electricity market does not correspond to a perfect competition, and there may be barriers to the entrance of new generators. In other words, there are constraints that prevent the construction of certain kinds of power plants, such as the infra-marginal generators (i.e. those that are below the marginal resource in the merit order). Among these constrains one can mention: political, social and environmental limitations to deploy new hydro and nuclear power plants. In these situations, considering only the economic theory, this electricity market may not work efficiently because the market cannot efficiently allocate feasible technologies in order to add new capacities to the power system.

Beyond that, the market can pass through a learning period until producers and consumers understand the risk involved and/or the market rules become suitable and trustful. But this learning process can be long and painful, which may include several rationing periods, and politicians can intervene before the market complete its learning.

Moreover, it should be recalled that when risks are shifted from consumers to producers, power plants with large fixed cost and with long construction times are viewed with great skepticism, even if variables costs are low. Moreover, base-load technologies, like hydro and nuclear, are those characterized by low variable costs and large investment costs, while mid-load and peak-load technologies have lower investment costs but larger variable costs. Finally, as noted by [FSR, 2014a], to make investments at this scale and to raise the necessary finance, producers need to manage the price risk associated with the short-term price volatility.

The aforementioned situation is faced when moving from Model 2 (the single buyer) to Model 3 or Model 4 (the wholesale and retail competition, respectively). However, while under certain circumstances of Models 3 and 4 (where there is a market-based economic and then the decision to invest is decentralized) there may be reluctance of the entrepreneurs to invest to expand the generation capacity, in the Model 2 there is the possibility of an error of the central planning conducted by the government.

To overcome this situation and deal with the supply adequacy, it is recognized the importance of having a capacity mechanism, which is straight designed to promote generation investments in order to ensure the security of supply. In fact, the concern previously described explains why countries adopt measures to ensure the adequacy of installed generating capacity.

As pointed out by the Agency for the Cooperation of Energy Regulators (ACER) in [ACER, 2013], "the political sensitivity to capacity shortfalls, as well as practical and theoretical uncertainties as to if and when investors will build new generation capacity, has compelled a number of Members States of the European Union to intervene by introducing Capacity Mechanisms (CMs) in order to provide additional stimulus to investors and to ensure that a sufficient amount of capacity will be available". A variety of CM mechanisms have been proposed by ACER. As reported by ACER, five different types of CM can be defined according to whether they are volume-based or price-based[25]. These five types of mechanisms are presented in Figure 2.16 and discussed below.

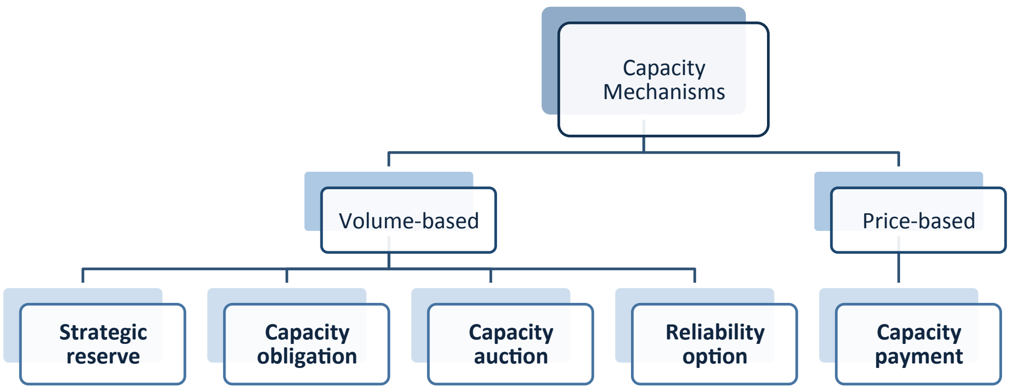


**Figure 2.16 – Types of capacity mechanisms, adapted from [ACER, 2013]**

The next paragraphs detail these capacity mechanisms:

- **Strategic reserve**: Generation capacity is set to ensure security of supply in exceptional circumstances, which can be signaled by prices in the day-ahead, intra-day or balancing markets increasing above a certain threshold level. An independent entity determines the amount of capacity to be set and dispatches it whenever due. Capacity is procured through auctions for the specified amount, for example, on a year-to-year basis. These

[25] A similar classification is found in [FSR, 2014a] since these mechanisms are grouped in: "capacity markets", defined as volume-based mechanisms in which a fixed amount of capacity is predetermined (under this scheme the price is unknown and defined according to the offer of available capacity); and "capacity payments", defined as price-based mechanism in which the outcome of the capacity is unknown in advanced.

schemes may involve direct payments, payments in the form of options or mixed forms. Strategic reserve contracts can contain provisions for notification time, duration of activation, etc.;

- **Capacity obligation**: It is a decentralized scheme where obligations are imposed on large consumers and on load serving entities to contract a certain level of capacity linked to their self-assessed future consumption or supply obligations. The parties can fulfill their obligations through ownership of plants, contracting with generators/consumers and/or buying tradable capacity certificates (issued to capacity providers). These capacity certificates are essentially contracts that specify the required availability of the power plant (duration, notification time, etc.). Demand side resources may also be included as interruptible load contracts. Contracted generators/consumers are required to make the contracted capacity available to the market in periods of shortages. Failing to do so may result in penalties;
- **Capacity auction**: It is similar to a capacity obligation, though the capacity procurement process corresponds to a centralized scheme and an independent entity acts on behalf of the total demand. This entity calculates how much generation capacity consumers/suppliers require based on the expected total peak demand. The total required capacity is set several years in advance and procured through an auction by the independent entity. Contracted capacity should be available according to the terms of the contract;
- **Reliability option**: It is an instrument similar to call options. In this mechanism, consumers or an independent entity on their behalf buy options. As it was previously discussed when addressing the option market (Section 2.2.2.4), when the market price exceeds the strike price, sellers may be required to make the committed capacity available. In exchange, generators receive fixed revenues and benefit from a more stable and predictable income. A scheme based on it usually rests on an obligation imposed on large consumers and suppliers to acquire a certain amount of reliability options linked to their future consumption or supply obligations, which becomes similar to a scheme based on capacity obligations;
- **Capacity payment**: The simplest type of capacity mechanism is to provide direct capacity payments. The capacity payment is defined and controlled by an independent entity, and there are different methods of calculating the level of payments and how to target them. Capacity payments can correspond only to the present, but can also be applied to new capacity. In the latter case, the payment is explicitly aimed at amplifying the investment incentives for new capacity. Alternatively, capacity payment can also be applied to specific types of plants such as base-load and peak capacity units.

As we have seen previously, in order to address the problem regarding the generation adequacy in the long-term under a market environment, it can be relevant to implement capacity mechanisms. The basic motivation underlying these schemes is to provide extra income for generators that cannot recover their fixed costs through the difference between the market prices and the generation costs. Moreover, these capacity mechanisms can ensure the long-term ability of the power system to match the demand and the supply by inducing investment commitments by the generation companies.

## 2.4 Final remarks

In conclusion, after the analysis of the four electricity industry structures, the classification and the sequence markets, and the meet between the market design and the operation of the power plant regarding completeness in short-term and adequacy in long-term, it is summarized in this section the mains points and findings.

To bring the chapter to a close, Table 2.3 details a number of relevant issues of the preceding sections, including those two raised in Section 2.1 regarding the ultimate goals of the restructuring of the power sector: decrease of prices and tariffs; and sustainability and resilience of the industry. In addition, this table highlights aspects from Models 1 to 4 concerning competition, low tariffs, completeness of the market and security of supply. Bearing these themes in mind, the last column includes main conclusions and trade-offs of models. Besides that, to contextualize the case of study, it is indicated in this table where is Brazil in this overall picture and essentially how this market design works nowadays.

Model 1 has clear disadvantages if compared with the others. Despite the possibility to gain efficiency with economies of scale, a striking feature of this model, in practice it has been noted that negative factors overcome it. Examples of such factors are the inefficiency of the stated-owned players and the inability of the government to deal with the growing complexities of forecasting, financing, constructing, operating and maintaining the power system. When leaving Model 1 we are also eliminating, for the generation activity, the need to deal with the cost-based and incentive regulation. Moreover, if we move to Model 2 competition is added in the generation activity, and this activity represents around 50-60% of the electricity bill paid by end consumers.

The move from Model 2 to Models 3 and 4 is marked by tricky trade-offs. First of all, to go further in the liberalization process, market should be mature, i.e. with well-designed institutional arrangements, stable rules and favorable political environment. Thus, for some situations, it is important to have mechanisms to address the supply adequacy, and Section 2.3.2 describes useful mechanisms to attract investments for Models 2, 3 and 4.

Model 2 implements the “competition for the market” while Models 3 and 4 implement the “competition in the market”. The former is put in place through public auctions that ensure winners to sign a contract for a long period, and the latter handles with more diverse types of contracts and stimulates the innovation through competition that continually occurs on a day-by-day basis. However, the absence of long-term contracts increases the opportunities to exercise market power, and when shifting from Model 2 to Models 3 and 4 consumers may lose the bargaining power coming from the single buyer.

In Model 2 the producer surplus is captured by the consumers, once during the public auction the pay-as-bid procedure can be adopted and the tariff can be designed to capture the weighted average of each successful bid. A parallel approach can occur in Models 3 and 4 when applying the pay-as-bid settlement in a short-term market, but with opportunities to generator to cheat. However, in Models 3 and 4 with a centralized market like a day-ahead, loose pool price formation and uniform price procedure, the additional rents obtained by generators (i.e. the producer surplus in this short-term market) will be used to recover the fixed cost, once their bids intend to recover only variable costs. In the end, theoretically, if the market works properly, in all alternatives consumers will pay a fair electricity tariff.

**Table 2.3 – Comparison between Models 1, 2, 3 and 4**

<table>
<tr><th>Market structure</th><th>Competition</th><th>Low tariffs</th><th>Required tools</th><th>Security of supply</th><th>Trade-offs and main conclusions</th></tr>
<tr><td>Model 1<br>Vertically integrated utility</td><td>There is no competition</td><td>Through cost-based and incentive regulation</td><td>• State owned company<br>• Command and control management</td><td>• Central planning (consumers' risk)</td><td>Between models 1 and 2:<br>• Model 2 has the advantage of add competition into the most important part of the value chain (which should offset the loss of economies of scale), and at the same time eliminate the need to deal with the cost-based and incentive regulation.</td></tr>
<tr><td>Model 2<br>Single buyer<br>(Brazil)</td><td>Monopsony (sellers and one buyer dealing with wholesale quantities)<br><br>Competition for the market</td><td>• Through market-based principles<br>• Pay-as-bid: weighted average of each successful bid (price and quantity)</td><td>• PPAs<br>• Imbalance price calculation<br>• Mechanism for risk sharing<br><br>PS: Concerns about completeness of the market</td><td>• Central planning<br>• Long-term contracts with availability payment<br>• Mandatory bilateral contracting with physical backing</td><td rowspan="2">Between models 2 and 3:<br>• When market is not mature (confidence at institutions and rules) Model 2 is more reliable than Model 3;<br>• In Model 3 consumers may lose the bargaining power coming from the single buyer, but they gain competition in a different way and more incentives for innovation;<br>• The absence of long-term contracts increase the opportunities to exercise market power;<br>• If the market works properly, in all alternatives consumers will pay a fair tariff;<br>• In Model 2 the problem of completeness of the market is a relevant issue.</td></tr>
<tr><td>Model 3<br>Wholesale competition</td><td rowspan="2">Sellers and buyers in wholesale or retail market<br><br>Competition in the market</td><td rowspan="2">• Through market-based principles<br>• If uniform price: marginal cost of the last successful bid<br>• If pay-as-bid: possibility of bids above their own costs and close to the bid of the last supposed marginal generator</td><td rowspan="2">• Day-ahead market<br>• Intraday market<br>• Balancing market<br>• Imbalance price calculation<br>• Future market<br>• Forward market<br>• Options market<br><br>PS: Better completeness of the market</td><td rowspan="2">• Market-based<br>• Volatility of the short-term price<br>• Capacity mechanisms</td></tr>
<tr><td>Model 4<br>Retail competition<br>(Brazil)</td><td>Between models 3 and 4:<br>• Model 4 add high transaction cost, which must be overcome by transparency and technologies;<br>• The demand response can take part if there are hourly prices, these price signals are clearly available to consumers, and the tariff is reviewed monthly.</td></tr>
</table>

Model 4 allows the free choice of suppliers by consumers and it can add high transaction costs, which must be overcome by transparency and smart technologies. However, regardless of the adopted model, what is more important for the demand response to take place is the need to have a short-term price formation close to the operation of the power system, and an hourly basis electricity metering, and a monthly tariff review.

Moreover, it is worth reporting that no single design or solution is likely to work in all circumstances. Countries must find which market design features are more pertinent and which ones are not.  Thus, there is no one-size-fits-all market design. Rather than that it must be taken into account the characteristics of the country such as the available energy resources, the economic situation, social conditions, political conjuncture, environment constraints and, finally, the maturity of the existing market.

Regarding the Brazilian case, it can be noted that there is investment commitment once the successful generators of the public auction sign a long-term contract to build and operate a power plant in advance. So, regarding the adequacy of the market design for Brazil, this issue is fostered through long-term contracts with availability payment and a mandatory bilateral contracting scheme with physical backing. In other words, this corresponds to the capacity mechanism nowadays in Brazil designed to avoid the lack of investment. On the other hand, the completeness of the market is an issue not well addressed. Figure 2.17 illustrates the chain of events associated with this analysis, from the investment commitment, passing through the ex-ante contracts and scheduled production, until finally reaching the real production.

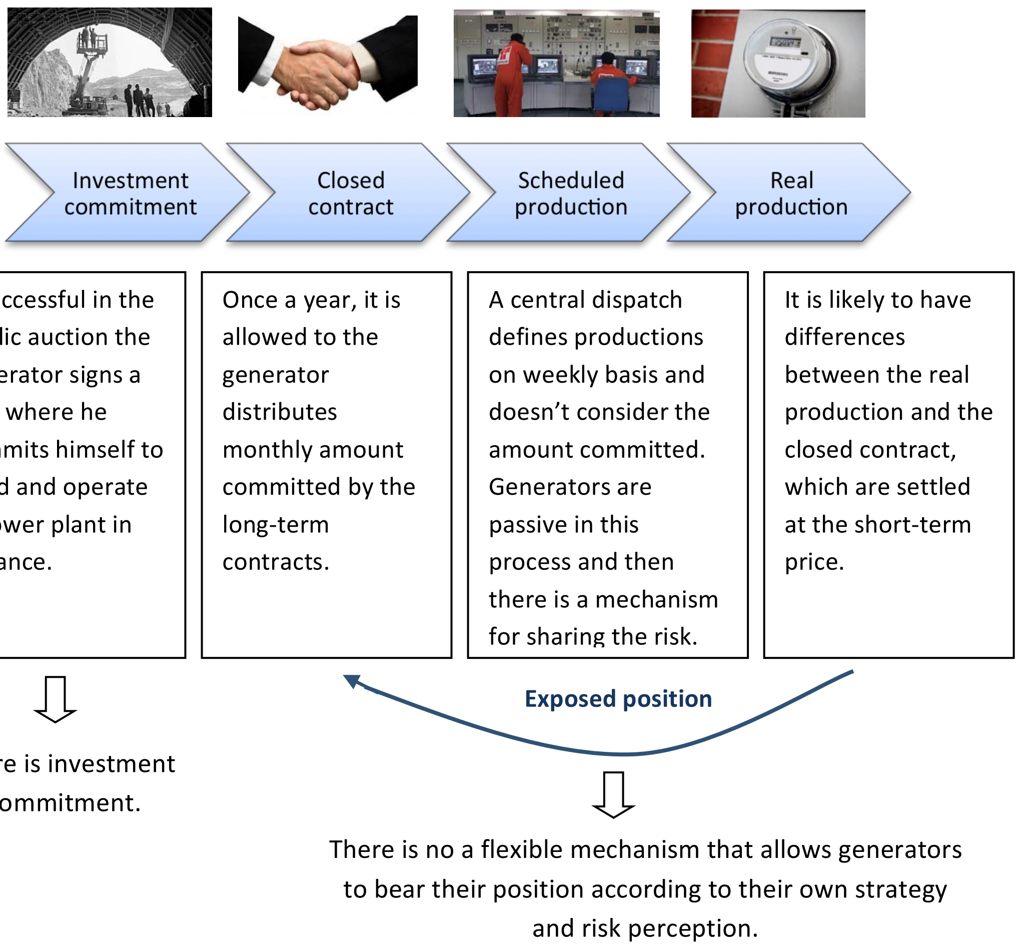


**Figure 2.17 – Brazilian case: from the investment commitment to the delivery of energy**

In the Brazilian electricity market, generators assume their commercial commitments mainly through long-term contracts, and through the seasonalization process of the contracted energy they are allowed to monthly distribute the energy committed by ex-ante contracts. However, they are not allowed to decide their own generation in order to endure their contracts, which can expose them to the possibility of buying electricity in the short-term market at its volatile prices. Finally, as the ISO dispatch is performed in a centralized way without considering closed contracts, a mechanism for sharing the risk of exposition automatically takes place in the accounting and settlement process of the Brazilian electricity market. This mechanism is called Mechanism for Reallocation of Energy, and it is known as *MRE.*

As can be observed, it is missing a flexible mechanism that allows generators to endure their positions according to their own strategy and risk perception. This research aims to investigate and develop a market design capable of improving the Brazilian market design completeness and, the same time, maintain the current features of the market design adequacy in long-term.

In the next chapter a more detailed description about the Brazilian electricity market is provided, and relevant concerns are examined in order to implement a more market-oriented approach. In Chapter 4, a new market design is proposed to enhance the flexibility for hydro to better allocate their risk of exposition without affecting the current level efficiency of the energy resources and of security of supply of the country.

# Chapter 3 – Brazilian Electricity Market

The Brazilian electricity market has certain peculiarities that contribute to considerably distinguish it from other markets. With a continental transmission system, a large and growing demand, a total generation installed capacity around 142 GW, from which about 70% comes from hydropower plants, the Brazilian electricity market, aiming to achieve a better efficiency of the service with lower tariffs, has gone through two large institutional and regulatory reforms in the last twenty years. Nowadays, it contains certain processes, mechanisms and instruments that distinguish it from other markets. All these features make this case an intriguing one.

In the next sections the aforementioned issues are addressed in order to provide a more comprehensive analysis of the case study.

## 3.1 General information

In this section it is briefly presented general information about the current Brazilian electricity sector in order to provide an overview, particularly regarding the reforms that were implemented and the current status quo (Section 3.1.1), quantitative aspects of the power system (Section 3.1.2), the legal framework (Section 3.1.3), which aims at providing a normative background for the participants' act, and the institutional framework (Section 3.1.4), i.e. the governance system and the powers and duties of the main institutions of this sector.

### 3.1.1 The reforms in the electricity sector and the current status quo

Before the 90s, the Brazilian power system consisted of vertically integrated companies. So, during this period, the electricity industry structure operated according to Model 1 detailed in Chapter 2. Then, the wave of electricity sector liberalization reached Brazil, and in 1995 started the implementation of what became known as the "first reform" of the electrical sector. This reform basically consisted of:

- Unbundling of generation, transmission and distribution activities in order to enhance tariff transparency and implement competition;
- Reduction of the role of the state-owned companies by the privatization process;
- Increase of the private capital participation to enable the expansion of the power system;
- Implementation of the right of free access to the transmission and distribution networks for all market participants;
- Creation of the electricity regulatory agency, the independent system operator and the market operator; and
- Creation of the Brazilian wholesale market and the short-term market.

Initially this reform promoted a transition to a market where agents could freely negotiate contracts (Law 9074/1995; Law 9648/1998), i.e. to a "free market model" close to Models 3 and 4 detailed in Chapter 2. Besides that, the quantities that were traded by contracts have been reduced whereas more trading in the short-term market was encouraged [Arango *et. al.*, 2006]. During this time, Brazil had a decentralized energy planning, but with an indicative energy planning conducted by the National Council for Energy Policy (CNPE).

Then, in 2001 Brazil experienced a major electricity supply crisis, which led to an aggressive energy rationing programme experienced from June 2001 to February 2002. The 2001/2002 electricity rationing had major economic and political impacts. This rationing encompassed about 80% of population, GDP and electricity consumption [Maurer *et. al.*, 2005]. Besides that, opposition parties identified the rationing as an evidence of bad government management, which led President Cardoso not to assure the election of his preferred successor during the election campaign of 2002, that lead to the election of President Lula [Rosa *et. al.*, 2013].

After examining the energy crises that occurred in a number of countries, [Maurer *et. al.*, 2005] stated that the main causes of the Brazilian rationing are:

- A sequence of years drier than usual (the system was and still is mostly constituted by hydropower plants). This severe drought can be seen as a cause of the crisis once the system would not have experienced an energy shortage if rainfall in the years preceding and during the crisis had been close to historical averages;
- Lack of incentives for Disco to contract by entering into PPA arrangements backed up by new generation. Discos' lack of willingness to contract was due to many regulatory and commercial reasons;
- The false sensation that supply and demand were "physically" balanced. From a contractual standpoint, Discos had energy to meet their current and future market requirements. Therefore, no new contracts seemed to be necessary. However, the ISO's predecessor overestimated the volumes of available physical energy specified in contractual arrangements when those contracts were put in place.

Consequently, the last two reasons stated above led to insufficient investments in generation, i.e. the "lack of investment" mentioned in the Section 2.3. This severe energy rationing is a significant historic fact to understand the currently Brazilian electricity model, since the misbalance between the supply and the demand was the main motivation for the revision of the previous model and the implementation of what became recognized as the "second reform" of the electrical sector.

This second reform was an electoral commitment of President Lula and it took Brazil to a structure corresponding to Model 2 (single buyer model), but preserving some features of Model 4 (competition in the retail market). In practice, a new regulatory framework (introduced by Law 10848/2004) was implemented in 2004, which brought back some old fundaments while adding new guidelines:

A. Reintroduction of the long-term centralized planning conducted by the federal government to address the security of supply. Thus, the expansion of the system doesn't rely on a market-based economy;
B. Competition through public auctions according to the single buyer model. The main target of this scheme is to provide affordable tariffs to the growing economy;

C. Implementation of long-term contracts (PPAs) with availability payment. The goal was to promote the installation of thermal power plants;

D. Requirement that consumers must be fully supplied by energy and power purchase contracts, and all contracts must be registered with the Brazilian market operator (CCEE);

E. Requirement that sellers must provide "physical coverage" for the sale of energy and power to entirely ensure their contracts; and

F. Restructuring of the retailing processes by the creation of two contracting environments: a "regulated" one related to the captive consumers, which is entitled *ACR* - Regulated Contracting Environment (similar to Model 2), and another one where free consumers can buy electricity, which is named *ACL* - Free Contracting Environment (similar to Model 4).

These two contracting environments (item F) are illustrated in Figure 3.1.

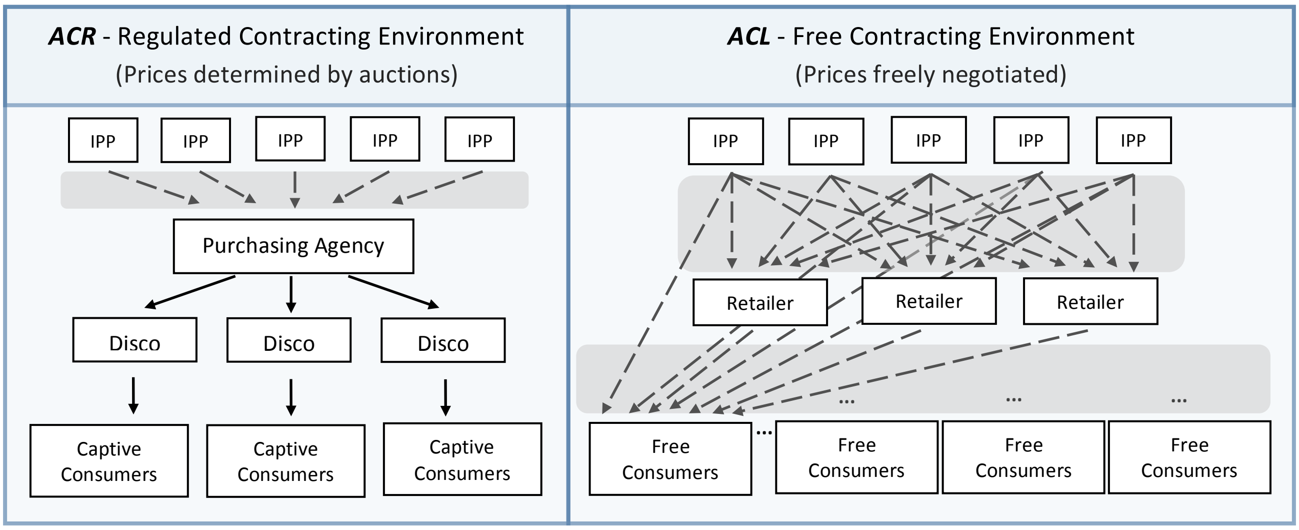


**Figure 3.1 – The two contracting environment in Brazil: *ACR* and *ACL***

Both the implementation of PPAs with availability payment (item C) and a mandatory bilateral contracting scheme (item D) with physical backing (item E) were adopted to guarantee the return of investments and to address the security of supply.

Regarding item D, it is relevant to reinforce that the electricity demand of both distribution utilities (on behalf of captive consumers) and free consumers must ensure the compliance of 100% of their consumptions by energy and power purchased through bilateral contracts, which must be registered at the market operator (Decree 5163/2004, art 2º, items II and III). Otherwise, specified penalties will be applied to them. As a result, this legal provision definitely imposes a bottleneck on the trading of electricity into the short-term market.

Concerning item E, it means that all electricity sold by sellers should be 100% physically backed (Decree 5163/2004, art 2º, item I). This "physical coverage for sale" consists of what is known as the “physical guarantee” or “assured energy”[26] of the power plant, and it must be related to its own power plant or with energy or power purchase contracts with other power plants. The physical guarantee is a crucial element to understand the Brazilian electricity market design, as it can be perceived throughout the entire Section 3.2.

The physical guarantee corresponds to the maximum amount of energy and electrical power associated with each power plant project. Relating to a hydropower plant, the physical guarantee corresponds to the maximum energy production that can be maintained almost continuously over the years, simulating the occurrence of thousands of inflow sequences created statistically, and assuming a certain risk of not feeding the load [ANEEL, 2013]. As a result, the physical guarantee of a power plant has the value of a certificate that determines the amount of energy that each power plant can trade in the Brazilian electricity market, either in the *ACR, ACL* or in the Brazilian short-term market (*MCP*).

By requiring that all energy contracts are "backed" to an effective generation capacity, it is avoided that the amount of contracted energy exceeds the supply capacity of the generator given a certain level of reliability [Instituto Acende Brasil, 2012]. The physical guarantee is then defined by the Ministry of Mines and Energy (MME)[27] and it is set in the concession contract or authorization grant of power plants (Decree 5163/2004, art 2º, § 2 º).

Moreover, in order to implement the centralized planning (items A and B), the following scheme was adopted: in the beginning of each year Discos must declare to the Minister of Mines and Energy their expected demand for 5 years ahead (Decree 5163/2004, art 13º), and they can also overestimate their demand until a certain amount (in order to obtain a reserve) with the guarantee that this cost will be passed on to the tariffs.

So, picking up all pieces of this new market design, regarding the market adequacy in the long-term and in order to address the security of supply, Brazil adopts a mix of:

- capacity obligation: it is required that 100% of the load must be contracted by bilateral contracts with physical backing (Decree 5163/2004, art 2º, items I, II and III);
- strategic reserve: it is passed on to the final consumers tariff until 105% of the total amount of electricity purchased by Discos to meet their annual load (Decree 5163/2004, art 38º) and specific national public auctions are implemented to contract reserve of energy (Law 10848/2004, art 3º, § 3º, and art 3ºA, regulated by Decree 6353/2008); and
- capacity payment: in the case of auctions for availability, after the national public auctions it is signed a PPA that includes an availability payment term (Decree 5163/2004, art 28º, item II).

[26] The “assured energy” is a term most commonly used to define the “physical guarantee" of the hydropower plants [CCEE, 2010].

[27] The MME established the methodology of calculation of the physical guarantee by the Ministerial Ordinance 258/2008 for new projects of power plants connected to the SIN (the Brazilian the National Interconnected System) and by the Ministerial Ordinance 463/2009, for hydros not centrally dispatched by the ISO.

These three mechanisms are highlighted in Figure 3.2.

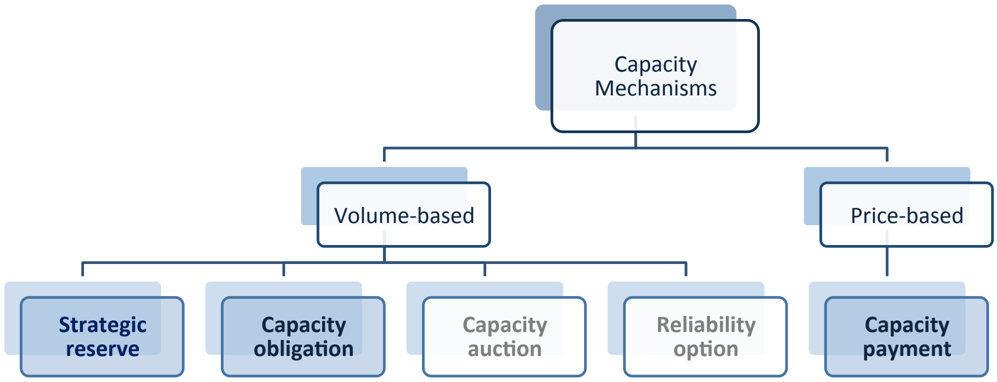


**Figure 3.2 – Capacity mechanisms in Brazil**

Table 3.1 presents the changes from the old model (in place until 1995), passing through the free market model that came from the first reform (in place from 1995 to 2003), to the current model, which resulted from the second reform (in force since 2004).

**Table 3.1 – Changes in the Brazilian electricity sector, adapted from [CCEE, 2014a]**

| **Old model**<br>(until 1995) | **Free market model**<br>(from 1995 to 2003) | **Current model**<br>(since 2004) |
|---|---|---|
| Financing through public resources | Financing through public and private resources | |
| Vertically integrated companies | Unbundling: generation, transmission, distribution and retail | Unbundling: generation, transmission, distribution, retail, import and export |
| Predominantly state-owned companies | Opening and emphasis on privatization of companies | Coexistence between private and state-owned companies |
| Monopolies | Competition in the generation and retail segments | |
| Captives consumers | Captives and free consumers | |
| Regulated rates in all segments | Prices were freely negotiated in generation and retail. | In ACL: Prices are freely negotiated in generation and retail. In ACR: single buyer auctions |
| Regulated market | Free market | Coexistence between regulated and free markets |
| Determinative energy planning conducted by GCPS planning group | Indicative energy planning conducted by National Energy Policy Council (CNPE) | Energy planning conducted the public Energy Research Company (EPE) |
| Contracting level required: 100% of Market | Contracting level required: 85% of market (until Aug. 2003) and 95% (until Dec. 2004) | Contracting level required: 100% of Market + reserve (5%) |
| Surplus and deficits of energy balance divided between buyers | Surplus and deficits settled at the Wholesale Electricity Market (MAE), the market operator. | Surplus and deficits settled at the Electric Power Commercialization Chamber (CCEE), the market operator. |

All these reforms came after the adoption of the liberalization of the electricity market. It began with an intervention to guide the sector to a more market-based economy and nowadays it returned to a situation characterized by centralized planning, but still maintaining a mix between free and regulated market.

### 3.1.2 The power system in numbers

Brazil has a large hydrothermal power system with strong predominance of hydro stations with multiple owners. This system is usually divided in two categories: the National Interconnected System, known in Brazil by the acronym *SIN*; and Isolated Systems. Figure 3.3 illustrates how different water basins in the *SIN* are electrically interconnected by transmission lines. In each water basin there are many hydropower plants installed as cascades of facilities in the main river and its tributaries. Examples of such cascades are provided in Figure 4.1 (Section 4.1).

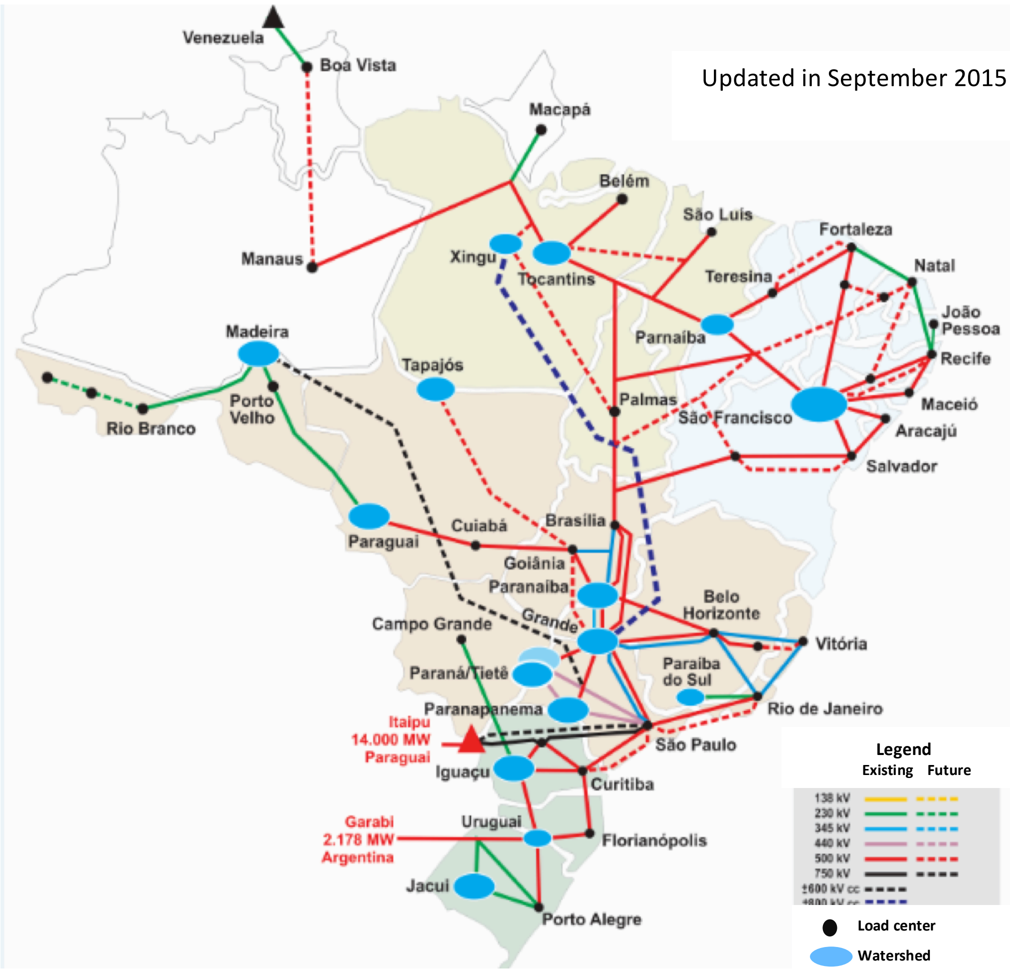


**Figure 3.3 – Energy integration of the Brazilian interconnected power system [ONS, 2015a]**

These interconnections have historically been focused on exploiting the country's vast hydroelectric potential, typically located far away from consumption centers, and to take advantage of energy complementarities between regional hydro areas (if there is a drought in one geographic area, other areas can compensate it by facing a wet season) [Rosa *et. al.*, 2013].

This power system has more than 100,000 km of transmission lines [ANEEL, 2014b], ranging from 138 kV to 750 kV, as shown in Figure 3.4. In addition, there are 68 transmission agents and 39 distribution agents directed connected to the grid of the *SIN* [ONS, 2015b]. The ONS (Brazilian Electric System Operator) operates this system acting as the ISO of the *SIN*.

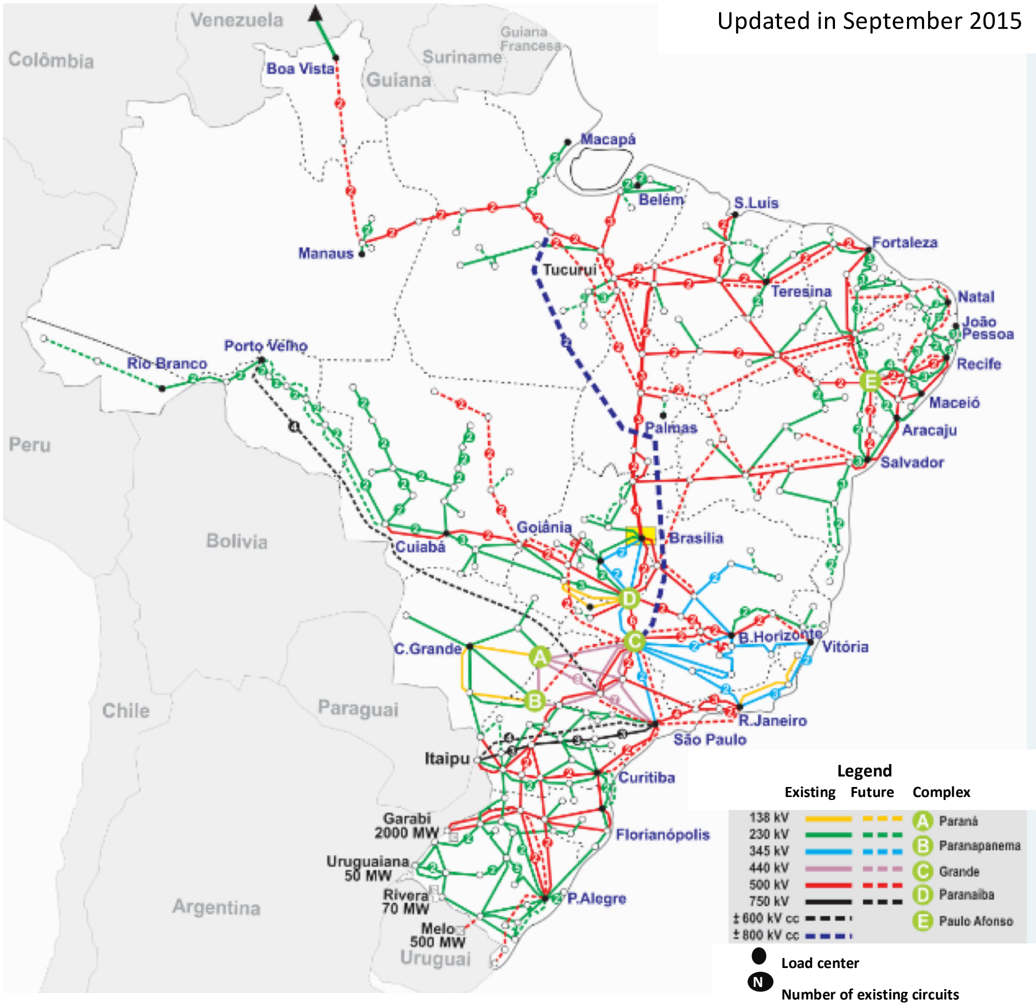


**Figure 3.4 – Brazilian transmission system [ONS, 2015a]**

The Brazilian population surpassed 200 million in 2013 [Estadão, 2014]. The main electricity consumption centers are interconnected through the *SIN*, which supplied 440 TWh of demand in 2012 [EPE, 2013]. The *SIN*, due transmission constraints, is divided in four submarkets: South (77.50 TWh in 2012), Southeast/Midwest (269.12 TWh in 2012), Northeast (63.89 TWh in 2012), and North (29.77 TWh in 2012). In addition, in the last 10 years the electricity consumption of the SIN has increased on average 4.5% a year.

Only around 1% of the electricity demand required by the country is located outside the *SIN* [ONS, 2015c]. These very small and isolated power systems are distributed in an area corresponding to 45% of the national territory, mainly dispersed in the Amazon area. These Isolated Systems serve about 1.2 million consumers [Eletrobras, 2014b], which corresponds to less than 1% of the population.

Regarding the generation segment, Table 3.2 presents a summary of the generation mix in operation and under construction. As can be noted, nowadays the Brazilian hydrothermal power system has more than 140 GW of total installed capacity, from which around 65% comes from hydropower plants and 35% from other energy sources. From these 35%, almost

29% come from thermal generation (including two nuclear stations). In this 29% around 7.2% (or 10.29 GW) are relative to gas and 7% (or 9.99 GW) to biomass generation [CCEE, 2015a], most of it from cogeneration units that use sugarcane bagasse and ethanol production. Wind corresponds to 4.74% of the total installed capacity, but its share is rapidly increasing with about 3 GW under construction. Additionally, it is expected that in the next few years more 21 GW of installed capacity will be added to the power system.

**Table 3.2 – Generation capacity in Brazil [ANEEL, 2015]**
Updated in September 8, 2015

| | | **Power plants in operation** | | | | **Power plants under construction** | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Type** | | Quantity of agents | Installed capacity (kW) | Installed capacity (%) | | Quantity of agents | Installed capacity (kW) | Installed capacity (%) | |
| Thermal (excluding nuclear) | | 2,773 | 40,984.59 | 28.57 | 34.77 | 20 | 1,634.63 | 7.64 | 26.69 |
| Nuclear | | 2 | 1,990 | 1.44 | | 1 | 1,350.00 | 6.31 | |
| Wind | | 269 | 6,586.13 | 4.74 | | 111 | 2,724.98 | 12.74 | |
| Solar | | 27 | 25.23 | 0.02 | | 0 | 0 | 0.0 | |
| Hydro | *CGH:* very small | 522 | 363.32 | 0.26 | 65.23 | 1 | 0.84 | 0.0 | 73.31 |
| | *PCH:* small-medium | 468 | 4,834.57 | 3.48 | | 34 | 416.40 | 1.95 | |
| | *UHE:* large-very large | 197 | 87,699.90 | 61.49 | | 11 | 15,269.14 | 71.36 | |
| **Total** | | **4,258** | **142,483.71** | | | **178** | **21,396.01** | | |

This market comprises more than 4,000 generation agents, and the state-owned companies are still dominant (only 2 of the top 10 are private companies). Table 3.3 lists the 10 largest companies in Brazil in terms of the installed capacity. As can be seen, if considering the share per agent, the Brazilian generation market is no longer concentrated (the largest company holds less than 8% of the installed capacity). However, the three fist positions are subsidiaries of Eletrobras Holding, meaning that this state company holds alone 22%.

**Table 3.3 – Top 10 Brazilian generation companies in installed capacity [ANEEL, 2015]**
Updated in September 8, 2015

| **Position** | **Agent** | **Installed capacity (MW)** | **Share (%)** |
|---|---|---|---|
| 1º | Chesf | 10,615 | 7,5 |
| 2º | Furnas | 9,919 | 7,0 |
| 3º | Eletronorte | 9,199 | 6,5 |
| 4º | Tractebel | 7,323 | 5,1 |
| 5º | Itaipú | 7,000 | 4,9 |
| 6º | Petrobras | 6,718 | 4,7 |
| 7º | Cesp | 6,649 | 4,7 |
| 8º | Cemig | 5,986 | 4,2 |
| 9º | Copel | 4,929 | 3,5 |
| 10º | AES Tietê | 2,652 | 1,9 |

The hydro power plants in Brazil are officially divided in three groups:

- ***CGH*** or very small hydro: The category defined as "very small sized" is the one with an installed capacity equal or lower than 1 MW. In Brazil, these are known by the acronym *CGH* (Hydropower Central).
- ***PCH*** or small-medium hydro: The category "small-medium sized", which is called in Brazil by *PCH* (Small Hydropower), is related to those units with an installed capacity larger than 1 MW and equal or lower than 30 MW, with a reservoir area lower than 3.0 km2, as defined by the ANEEL Resolution 652/2003.
- ***UHE*** or large-very large hydro: The hydropower plants larger than PCHs are defined as *UHE* (Hydropower). In this case, the UHE group is classified into the category "large-very large sized".

The analysis of this work is focused on the "large-very large" and "small-medium" groups (i.e. on PCHs and *UHE*s). Appendix A presents the list of all hydropower plants considered in the simulation of the thesis (125 hydros), embracing 98% of the total installed capacity of the country. This list contains information regarding the first year of operation, installed capacity and physical guarantee, among others.

In summary, the Brazilian power system can be synthesized in term of three highlighted characteristics [Rosa *et. al.*, 2013]: i) a continental-sized transmission network; ii) large growth of electricity consumption; and iii) predominance of hydropower generation.

### 3.1.3 The legal framework

The electric industry began in Brazil on a local scale, with the private sector providing lighting services and where companies signed contracts with municipalities. So, the activities of this industry (generation, transmission and distribution) were organized just to meet the load of larger cities. However, some supply crises and the dissemination of the use of electricity led to political debates regarding the change of jurisdiction to explore this service. At that time, these debates were influenced by nationalization, centralization, and state interventionism trends.

In this context, it was approved the Water Code in 1934 [Decree 24643/1934], which is seen as the starting point for the regulation of this industry, and Decree 41019/1957, which regulated the Water Code. At that time it was expected to reorganize the through a centralized planning characterized by the direct action of the Union or through delegation.

In the same legal treadmill, Brazilian Federal Constitutions came gradually centralizing the treatment of electricity. In 1967 the activities related to electricity were introduced into the list of competences of the Federal Union[28], and this was maintained in the Federal Constitution of 1988, which is currently in force. Then, it is pertinent to point out that, according to the Brazilian Federal Constitution (b, Section XII, Article 21):

[28] Brazil is organized as a federative republic where 26 states, 1 federal district and several municipalities self-govern, but they are under a central federal government that represents the entity called Union. The Federal Constitution establishes the jurisdiction limit among the Union, states, federal district and municipalities.

> "It is the responsibility of the Union to operate, directly or through authorization, concession or permission, the services and facilities of electricity and the energy utilization of watercourses in conjunction with the States where hydropower potential is available."

So, companies, to legally act in the Brazilian market, must receive grants as a concessionaire, permitted or authorized. The transmission services are provided under the concession regime. The provision of electricity distribution service is done through concession or permission. In the case of generation, exploitation occurs through concession or authorization. Moreover, a generation company can be entitled as a self-producer, independent producer or public service:

- Self-producer: a generator that uses the energy produced for own consumption. If approved, it can also sell the energy surplus;
- Independent producer: a generator that intends to sell all or part of the energy produced by his own risk; and
- Public service generator: a generator that produces electricity whose destination is classified as a public service.

Furthermore, regarding the hydropower plants and according to the current legislation (Law 9074/1995, Law 9427/1996 and Decree 2003/1996), it is given the concession grant for: all hydros classified as self-producer or independent producer with installed capacity larger than 50 MW; and all public service generators with an installed capacity higher than 1 MW. In other words, all representative hydropower plants nowadays have to operate as a concessionaire of electricity generation. In order to do so they sign a concession contract with the granting entity and then receive the right to explore the electricity generation during a specific period (lasting up to 35 years).

It is relevant to point out that representative hydros usually participate in public auctions, which operate according to the single buyer model (Model 2), and offer price bids considering that both the fixed cost (investment) and variable cost will be recovered along the concession period.

Additionally, in this scenario both state-owned (from the state and federal level) and private companies act in the generation, transmission, distribution and retail activities, and all electricity produced is consumed by three types of final consumers:

- Captive consumers: are those consumers who are only allowed to buy electricity from the Disco that is responsible for the area where these consumers are located. Therefore, this kind of consumers are supplied under regulated conditions;
- Free consumers: are those with a power equal or larger than 3 MW, which are given the right to freely choose their electricity suppliers, and who have already chosen not being served by regulated tariffs (Law 9074/1995); and
- Special consumers: are those free consumers with power exceeding 0.5 MW that buy electricity from solar, wind and biomass units, as well as from some hydros (PCHs), since all these generators meet certain criteria (Law 9427/1996).

The special consumers' category was implemented with the purpose of encouraging the development of such alternative renewable energy sources, since both special consumers and generators take advantage from a reduction in the fee related to the use of the distribution and transmission networks.

### 3.1.4 The institutional framework

Regarding the governance system, the new model of the Brazilian electricity sector created new institutions and altered the functions of some existing ones. Figure 3.5 presents the current institutional framework.

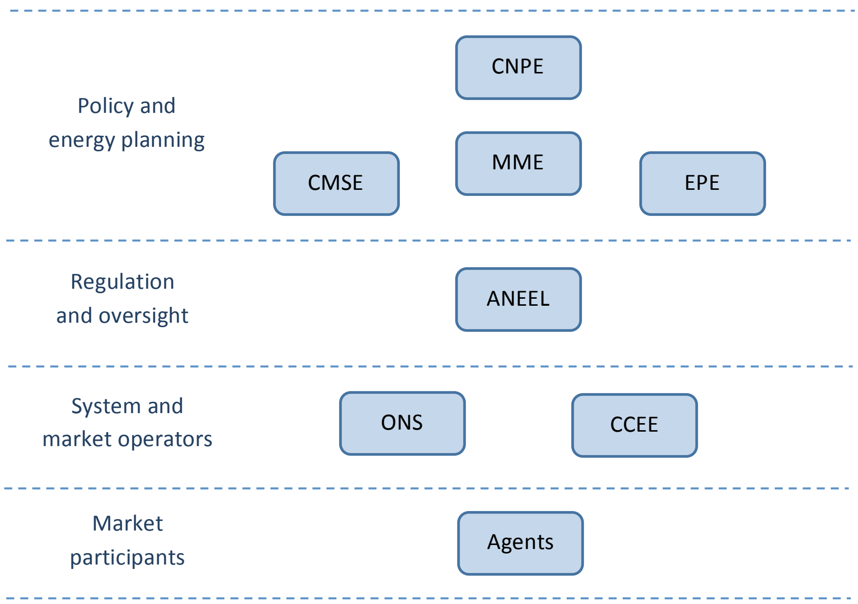


**Figure 3.5 – Institutional framework of the Brazilian power sector**

As mentioned in Section 3.1.1, Brazil has a centralized planning regarding the energy supply adequacy, and this issue has been a constant concern, especially after Brazil experienced a serious shortage and power rationing. Furthermore, during the restructuring process of the sector in 2004, this question was strongly embedded within the powers of institutions that constitute the governance system of the Brazilian electricity sector nowadays, as it can be clearly seen below.

The CNPE (National Council for Energy Policy) is the advisory institutional of the President of the Republic and has the assignment to propose national policies and specific measures to promote the rational use of energy resources in the country, to regularly review the energy matrices, to establish guidelines for specific programs, and to suggest the adoption of measures required to ensure the supply of the national electricity demand, among others. The CNPE was created by Law 9478/1997, it is chaired by the Minister of Mines and Energy and it contains: 9 ministers of states, 1 representative of the Brazilian states and of the federal district, 2 experts in the energy field (one related to the civil society and another to universities), the executive secretary of the MME and the CEO of EPE.

The MME (Ministry of Mines and Energy) is responsible for the formulation, planning and implementation of the actions of the federal government regarding the national energy policy in accordance with the guidelines defined by CNPE. The MME is also responsible for establishing the planning of the national energy sector (with the support of the EPE), for monitoring the security of supply of the Brazilian electricity sector (with special performance by the CMSE), and for defining preventive actions to restore security of supply in the case of imbalances between the energy supply and the demand.

The EPE (Energy Research Company) was established by Law 10847/2004 and created by Decree 5184/2004. It is a state-owned company linked to the MME with the purpose of providing services to support the energy planning. Among others, its duties include: studies and projections of the Brazilian energy matrix, and the identification and quantification of energy resources potential, including studies to determine the optimal utilizations of the hydro energy potential.

The CMSE (Electricity Sector Monitoring Committee) is responsible for supporting the MME regarding the monitoring of the security of supply. The CMSE was created by Law 10848/2004 as a body established under the MME to mainly assess the conditions of supply and service at predetermined periods (long, medium, short and very short-term). It is composed by the Minister of Mines and Energy, the committee coordinator, four representatives of the MME and the CEOs of the following institutions: ANEEL (Brazilian Electricity Regulatory Agency), ANP (Brazilian Oil and Gas Regulatory Agency), EPE (Energy Research Company), CCEE (Electric Power Commercialization Chamber, the market operator), and ONS (Brazilian Electric System Operator, the system operator).

ANEEL is the Brazilian electricity regulatory agency. It regulates and oversights the generation, transmission, distribution and commercialization activities, mediates conflicts of interest between agents of the electricity sector and between them and consumers, as well as stimulates competition between agents and ensures the quality of service, fair tariffs, the electricity universalization, among others duties. ANEEL was created by the Law 9427/1996, and it is an authority over special arrangements, linked to the MME, but conceptually designed to have independence regarding its decisions and internal administration, and financially supported by a levy included in electricity tariffs. ANEEL is headed by a General Director and four Directors, under a board committee. Their mandates are for four years, and one only renewal is permitted. The five directors are appointed by the President of the Republic, and these appointments are subjected to prior approval of the Senate.

The current market operator, the CCEE[29], was introduced by the Law 10848/2004 and created by the Decree 5177/2004. It is a non-profit private entity under ANEEL regulation and supervision. The CCEE is mostly intended to facilitate the trade of electricity in the *SIN* in both the Regulated Contracting Environments - *ACR* and the Free Contracting Environment – *ACL* (both discussed in more detail in Section 3.2), and to perform the accounting and settlement of the transactions in the Brazilian short-term market. To do that, CCEE must:

- promote the measurement of generation and consumption data from all CCEE Agents;

[29] The CCEE replaced the first Brazilian wholesale electricity market, called by MAE (Wholesale Energy Market), which was established by the Law 10433/2002.

- register all the contracts signed within the framework of the *SIN*;
- perform the accounting of the electricity and set the exposed positions;
- compute the Settlement Price Differences (*PLD*), the Brazilian short-term price; and
- perform the financial settlement of amounts arising from purchase and sale of electricity carried in the short-term market.

The coordination and control of the generation and transmission operation for the entire *SIN* is carried out by an entity called ONS, which is the Brazilian national ISO. The ONS, as the CCEE, is also a non-profit private entity under ANEEL regulation and supervision. It was created by the Law 9648/1998 and regulated by the Decree 2655/1998, which was amended by Decree 5081/2004. In accordance to its legal duties, the ONS must be focused on the energy optimization at the lowest operation cost and with the guarantee of quality and safety standards, while respecting constraints imposed by multiple water uses and by limitations associated with generation and transmission facilities. So, the ONS core functions are to:

- plan the operation of the system and perform the centralized dispatch of the generation power plants, aiming at optimizing the interconnected submarkets;
- monitor and control the operation of the *SIN* and of the international interconnections;
- contract and manage ancillary services; and
- propose to authorities the expansion and reinforcement of the network.

The last element in Figure 3.5 is entitled “agents” and it represents all market participants that operate in the generation, transmission, distribution and retail activities, plus the free and special consumers.

Lastly, it is also worth commenting the role of the Eletrobras company in the Brazilian governance system. Eletrobras is a holding that acts in the generation, transmission and distribution segments, and that also controls the Research Center for Energy known as CEPEL. Its shares are listed in the São Paulo, Madrid and New York Stock Exchanges, and the federal government holds 54.46% of the ordinary shares of the company being, therefore, the major stockholder [Eletrobras, 2014a].

In addition, contrasting with the operation of a company that should be profitable, Eletrobras also supports government programs such as the Program of Incentives for Alternative Electricity Sources (*PROINFA*), the Light for All Program (the national program for universal access of the end users to electricity), and the National Energy Conservation Program (*PROCEL*). Besides that, Eletrobras also manages, on behalf of the federal government, the financial resources so-called "sector funds" such as the Global Reversion Reserve (*RGR*), the Energy Development Account (*CDE*) and the Account of Fossil Fuel Consumption (*CCC*).

## 3.2 From Brazilian market results to the physical operation of the power system

To recap, Brazil has the Model 4 (competition in the retail market), named *ACL*, for those eligible consumers that fit in the characteristic of free consumers or special consumers, and

Model 2 (single buyer model), entitled *ACR*, for the final consumers that are not free to choose their supplier (i.e. captive consumers).

In the *ACR*, the prices are determined by national public auctions. Differently, in the *ACL* prices are freely negotiated between buyers and sellers through a non-organized market like OTC, or through emerging private electronic platform such as the BRIX (Brazilian Intercontinental Exchange) [BRIX, 2014] and the BBCE (Brazilian Energy Trading Desk) [BBCE, 2014]. These platforms provide contracts for the current month or for future delivery (monthly, annual and multiyear term) with a fixed price (R$/MWh) or a variable price (*PLD* + premium). Nowadays, the *ACL* represents around 30% of the national electricity demand, while the *ACR* embodies 70% [APINE, 2014].

Additionally, there is also the short-term market, in Brazil known as *MCP*, which is designed to account and settle the differences between the contracted energy and the generated/consumed energy amounts.

As the focus of this research is on the wholesale level, in order to analyze the Brazilian case from its market results to the physical operation, the following sections cover: the national public auctions of the *ACR* (Section 3.2.1); the seasonalization mechanism, which allows the monthly distribution of the physical guarantee and the energy committed by the ex-ante contracts (Section 3.2.2); the centralized dispatch carried out by ONS (Section 3.2.3); the mechanism to share the risk associated with the centralized dispatch, known as *MRE* (Section 3.2.4); and the Brazilian short-term market or *MCP* (Section 3.2.5).

### 3.2.1 The national public auctions

In the *ACR*, only distribution companies (Discos) participate from the demand side on behalf of their captive consumers. Besides, public auctions are the only way that they have to buy large volumes of electricity. The sellers are generation companies (Gencos), and auctions take place according to the purchase scheme of the single buyer model (Model 2).

This process begins when Discos submit to MME their demand projections over a five year horizon. As mentioned in the Section 3.1.1, Discos are required to do that in the beginning of each year. Then, MME, together with EPE, set the total market volume that will be offered through auctions. In the sequence, ANEEL, or CCEE if nominated by ANEEL, coordinates the auctions where Gencos compete by offering bids. The winners then sign PPAs with Discos. These contracts set the price and the amount of energy and power contracted throughout the grant period. Finally, tariffs of captive consumers are calculated as the weighted average of the pairs of price and quantity associated with the cleared bids (i.e. according to the equation 2.1 presented in Section 2.1.3).

These auctions have solidified the second structural reforms of the sector, and they play a central role with regard to security of supply since it is through them that the government coordinates the expansion of the electricity generation in Brazil [Instituto Acende Brasil, 2012].

In order to achieve their purposes, these auctions address both the “new” and “old” energy. The new energy auctions take place 3 or 5 years before the initial delivery time to allow entrepreneurs to compete and sign PPAs before the construction of power plants. So, they are respectively known as "A-3 auctions" and "A-5 auctions". In A-3 auctions, projects with shorter construction time take part, such as wind, medium hydros (*PCHs*), and thermal power plants (except coal and nuclear), while large hydro (*UHE*s) and coal thermal power plants usually participate in A-5 auctions.

Into the category of auctions designed to buy "new energy" there are also specific auctions promoted to contract electricity from relevant projects classified as "strategic" or of "public interest" by the CNPE. Because of that they are known as "structuring projects auctions". Usually, this typically refers to project associated with very large hydros (*UHE*s) such as Belo Monte (11.23 GW), Jirau (3.75 GW) and Santo Antônio (3.15 GW) hydropower plants.

Moreover, there are also specific auctions designed to buy electricity only from renewable energy sources such as wind, PV, biomass and *PCH*. They are known as "alternative source auctions" and were created to encourage the diversification of the national energy matrix.

Auctions that intend to buy electricity from power plants already in operation (i.e. existing generation or "old energy") can have the delivery time starting just one year after the date of auction. They are therefore called "A-1 auctions". Moreover, they can be in place in the same year of the beginning of the electricity supply, and thus they are identified as "adjustment auctions".

Figure 3.6 illustrates these kinds of auctions and also indicates the period during which the concession contract is effective.

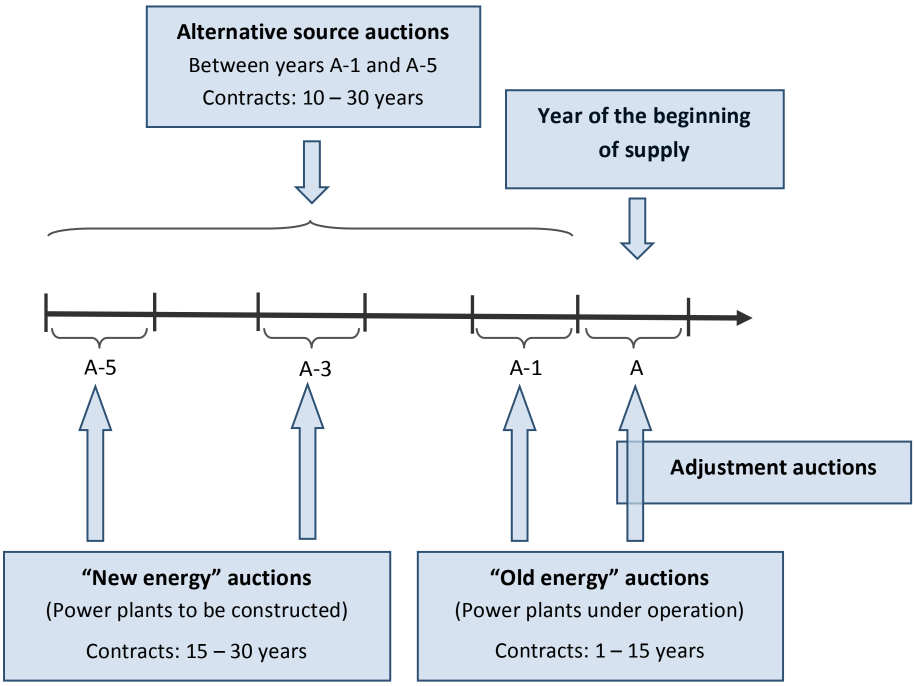


**Figure 3.6 – Types of auctions regarding the delivery time, adapted from [MME, 2014]**

Besides these auctions, there is a special category of auctions particularly designed to address supply adequacy: the "reserve energy auction". According to [MME, 2014], "reserve energy auctions aim at raising the level of security of supply of the SIN with the energy coming from power plants specially arranged for this purpose".

Furthermore, these auctions are designed to buy either energy or capacity [Instituto Acende Brasil, 2012]:

- Quantity type contract: In this case, the seller (generator) commits to deliver a certain amount of electricity (MWh) during a specific period at a pre-defined price. This feature corresponds to a typical forward contract. As a rule a hydropower plants signs this kind of contract. Any difference between the contracted energy (ex-ante contract) and the effective generation (real production) must be compensated by the seller by the settlement of this difference at the short-term market (i.e. the generator must buy or sell this difference in the MCP);
- Availability type contract: In this case, the seller (generator) receives a fixed remuneration to make available a specified capacity (and to recover its fixed cost), plus an additional remuneration for each effective produced MWh (to recover its variable cost). In other words, this kind of contracts corresponds to a PPA with availability payment, and they have been adopted to those power plants with larger variable costs, like thermal power plants. In each month it is paid the availability quota, and when dispatched the generator receives the payment for its generation on a monthly basis.

Moreover, to compare and score different projects from the availability type contracts (i.e. thermal power plants with diverse technologies and different variable costs), the auction system uses a cost benefit index (known as *ICB*), that considers the estimated dispatch and fixed and variable costs of each power plant. This index is the sum of the fixed cost (paid by consumers for the availability of the power plant) and the variable cost (forecasted operation cost based on dispatch expectation) divided by its availability [Rego, 2013].

Typically, one A-3 and one A-5 auctions are carried out every year. From December 2004 (when the first energy auction was held) to 2012, 31 auctions have been carried out in Brazil: 10 on existing energy, 12 on new energy, 3 on structuring projects, 4 on reserve energy, and 2 on renewable energy. Table 3.4 presents an overview of ACR auctions carried out from 2004 to 2012 and Figure 3.7 shows the average prices by energy source.

**Table 3.4 – *ACR* auctions between 2004 and 2012 [Rosa *et. al.*, 2013]**

| **Auction type** | **Trade volume** (MW average) | **Average price** (US$/MWh) | **Number of contracts** |
|---|---|---|---|
| New energy | 19,987 | 45.46 | 1,612 |
| Old energy | 22,478 | 61.90 | 6,728 |
| Alternative source | 900 | 74.05 | 1,146 |
| Reserve energy | 2,189 | 72.83 | 176 |
| **Total** | **45,554** | **59.17** | **9,662** |

Belo Monte hydropower plant is a case of a structuring project auction. It has an installed capacity of 11.23 GW, it was auctioned in 2010, and has the lowest price (US$ 42/MWh). Wind price evolution is noteworthy. It started at the level of US$ 152/MWh in the feed in tariff scheme carried out through the *PROINFA* government program in 2005, but has been falling significantly in the more recent auctions.

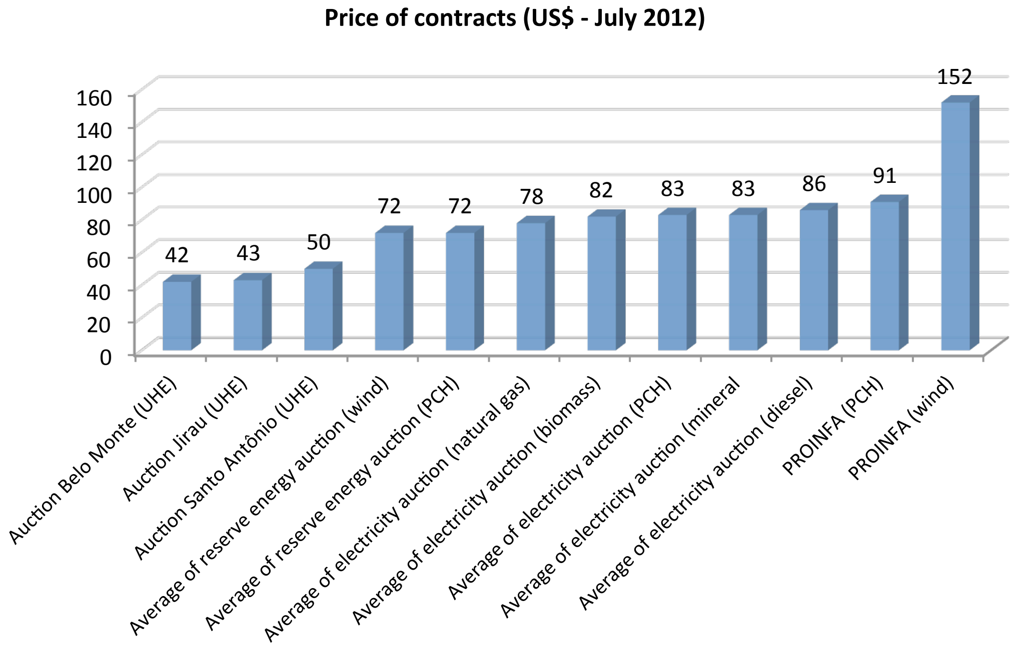


**Figure 3.7 – Average prices by types of auctions in Brazil [Rosa *et. al.*, 2013]**

Besides, it is important to note that these prices only consider the cost to produce electricity, and some projects are far away from the load center (specially hydros), which adds significant transmission costs to the tariff paid by final consumers.

### 3.2.2 The seasonalization and modulation process

After sellers and buyers sign PPAs coming from the public auctions, these contracts are registered by the CCEE, the Brazilian market operator, in order to be considered in the accounting and settlement process of the Brazilian short-term market (*MCP*). Besides that, these records are needed also due to the calculation of penalties for insufficient physical coverage for the commercialization of the energy and power. Then, when a power plant becomes available for operation (i.e. the construction phase of the project is completed), the CCEE will consider its physical guarantee available to be settled in the *MCP*. Following, the contracted energy[30] and the physical guarantee, both in “MW average”, are transformed in annual amount of electricity in “MWh” [CCEE, 2010].

[30] The contracted energy can be the total or partial amount of physical guarantee once it is the physical guarantee that determines the maximum quantity of energy that can be trade.

In December of every year, generators can perform a seasonal adjustment of the physical guarantee [CCEE, 2012a]. This mechanism is called "seasonalization" of the physical guarantee, and it allows generators to allocate the MWh annual amount in monthly amounts. If they do not opt to perform this seasonal adjustment, the seasonalization is performed by CCEE uniformly throughout the year, i.e. according to a "flat profile".

Moreover, if a change of the physical guarantee of a power plant[31] occurs, a review of the seasonalization should be performed. If there is an increase of the physical guarantee, the review of the seasonalization is of responsibility of the agent. If there is a decrease, the revision is conducted by the CCEE proportionately to the amounts already allocated in the seasonalization process. Besides the monthly distribution (seasonalization), these MWh are also allocated in hour quantities, in a process called "modulation". Thus, through this process, after the distribution in hourly values, the physical guarantee of the hydros is aggregated in weekly values by load steps..

In order to illustrate the seasonalization and modulation processes of the physical guarantee, Figure 3.8 shows an example of an hydro with 85 MW average of physical guarantee (installed capacity equal to 170 MW and capacity factor equal to 50%) in the year 2013. Once 2013 had 365 days, the amount of physical guarantee is equivalent to 744,600 MWh (85 MW average times 365 days times 24 hours). This amount is then monthly allocated (seasonalization). Finally, for every month, the weekly allocation is carried by load step (modulation).

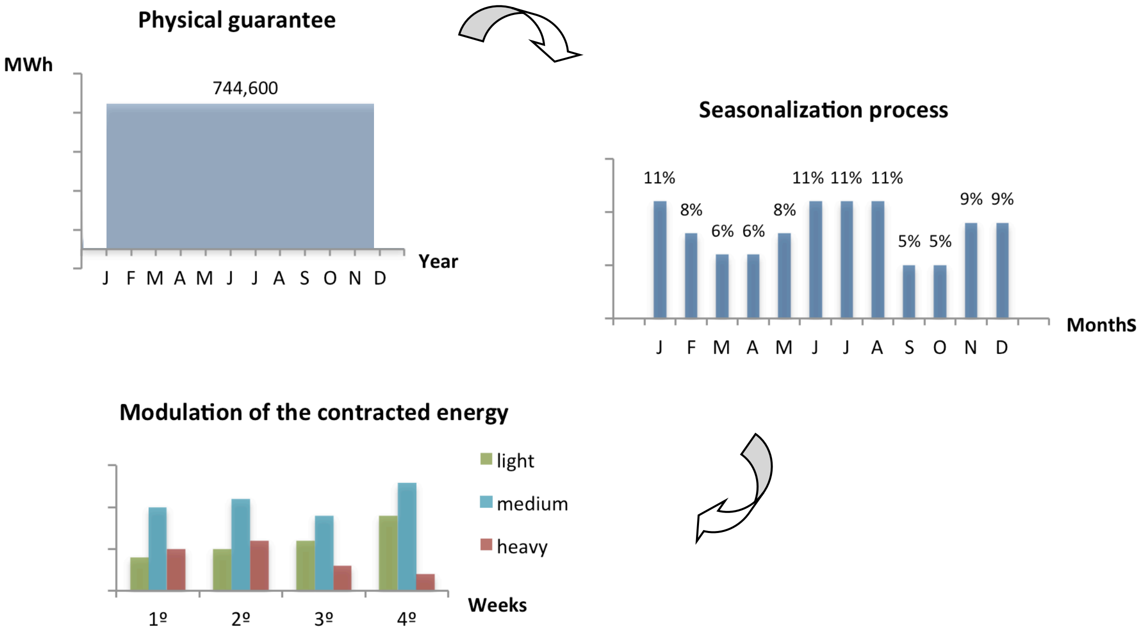


**Figure 3.8 – Seasonalization and modulation processes, adapted from [CCEE, 2010]**

[31] The Decree 2655/1995, in its article 21, § 4º, states that the value of the physical guarantee allocated to each hydropower plant will be reviewed every five years (ordinary review) or upon the occurrence of relevant facts (extraordinary review), and the MME Ministerial Ordinance 861/2010 establishes the relevant facts and methodology for the extraordinary review of the physical guarantee of hydros centrally dispatched by the ONS.

Besides the physical guarantee, which corresponds to the certificate that determines the total amount of energy that can be traded in the Brazilian electricity market (either in the *ACR, ACL* or *MCP*), the actually contracted energy can also pass through the seasonalization and modulation process. To give an example, let's consider the case of the contracts known as *CCEAR*s (Contracts to Trade Electricity into the Regulated Contracting Environment), which is the main kind of contract that come from the auctions of the *ACR* and it is designed to buy electricity from existing projects and new ones.

In *CCEAR* for quantity case, Discos can carry out the seasonalization of the contracted energy for the following year through bilateral negotiations with each generator. Thereby, Discos can monthly allocate their contracted energy to optimize their power purchase transactions. If an agreement between the two parties (generator and Disco) is not obtained, the CCEE will apply the load profile declared by the Disco concerning to the *CCEAR* [CCEE, 2008]. Moreover, the modulation of this kind of *CCEAR* is automatically performed every month taking into account the remaining load profile of the Disco (i.e. the resulting load after the subtraction of all the others contracts of the Disco) [CCEE, 2010]. Differently, the *CCEAR* for availability must always have a flat seasonalization, and the modulation will be monthly ex-post calculated, in accordance to the actual load of the Disco.

To conclude, from the point of view of generators: in one hand, they are allowed to define the monthly amount of their physical guarantee (through the "seasonalization of the physical guarantee"); and, on the other hand, they can also try to come to an agreement with the Disco in order to also define the monthly energy committed by the *CCEAR* that they have signed (through the "seasonalization of the contracted energy"). Regarding the definition of the hourly amount and concerning physical guarantees and *CCEAR*s, the modulation process is automatically performed.

Therefore, the seasonalization of the physical guarantee and the seasonalization of the contracted energy embody the flexibility that they have regarding (i) the allocation of their long-term generation capacity (physical guarantee), and their closed long-term contracts (ex-ante contracts). Nevertheless, both amounts have to be seasonalizated just once a year (first, the seasonalization of the *CCEAR*s, then, the seasonalization of the physical guarantee). This is the "window" that generators have to define, for the subsequent entire year, their "profile" regarding their physical guarantee (production that can be maintained almost continuously over the years) and their contracted energy (commitment to deliver energy).

### 3.2.3 The centralized dispatch carried out by the ISO

According to [Barroso et. al., 2005], hydro-based systems have the most diverse ways for system scheduling and price formation. In Brazil, a centralized scheduling of resources is used, where hydro stations are scheduled based on the water values (no price bidding) which in turn are calculated by a chain of stochastic optimization models.

The Brazilian case is a centralized market (addressed in Section 2.2.1.4) with a tight pool price formation (addressed in Section 2.2.1.5). The centralized dispatch of the hydrothermal power system is carried out by the ONS, the Brazilian ISO, and its goal is to minimize the total operating cost corresponding to the sum of the immediate cost and future cost using a set of computational models.

As explained by [Santana, 2004], the minimum cost problem looks for a trade-off between saving water now and using thermal fuel (if the inflow expectation is low) or using water now and saving thermal fuel (if the inflow expectation is favourable). These decisions can have two undesirable consequences. The first one has a negative effect: spillage is possible in the future if the hydrological regime is contrary to what was being planned. The second one also has a negative effect: an energy deficit may occur if it was used water in the present and the future inflow is low. An instructive scheme, which became usual in Brazil to describe this decision process, is presented in Figure 3.9

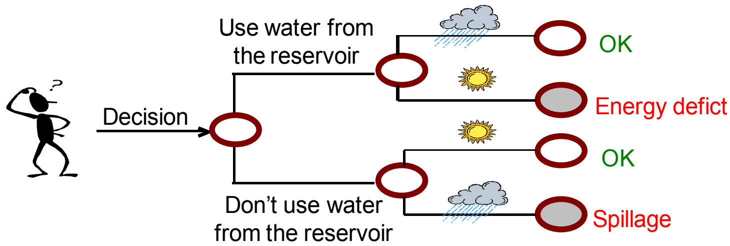


**Figure 3.9 – ISO's decision process in a hydrothermal power system**

As can be noted, the optimal strategy decision is associated with a temporal perspective: a decision made today will affect operating costs in the future. So, the dispatch procedure aims at finding the balance between the benefit of using water now and in the future, measured in terms of the expected fuel economy of thermal power plants [CCEE, 2010]. Figure 3.10 shows the future, immediate and total cost functions associated with this problem.

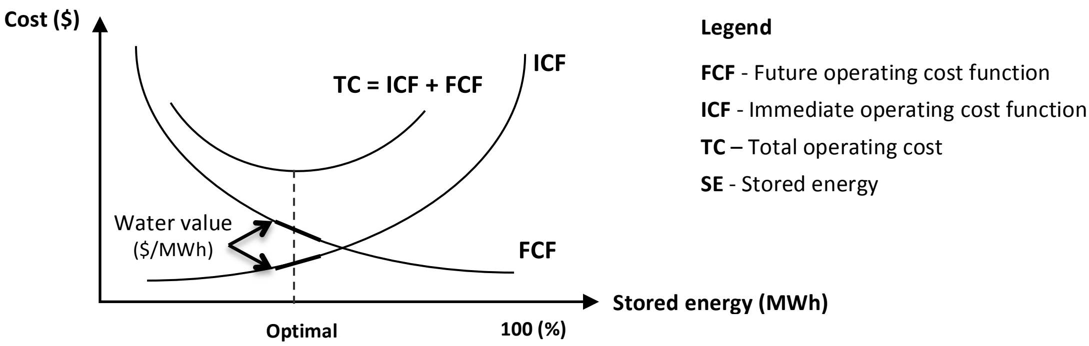


**Figure 3.10 – Future and immediate cost functions [ONS & CCEE, 2011]**

From Figure 3.10 it can be seen that if it is decided to store 100% of the water, it is necessary to use all thermal power plants to meet the demand. Then, the ICF has a larger value, but, since it was saved water for later use, the FCF is low. So, whilst in the present less hydros are widely used, more fuel is spent. Thus, in the future more hydros and less thermal power plants will be used. The minimum total operating cost is obtained when the derivative of total costs (TC = ICF + FCF) is equal to zero (point that minimizes the sum of immediate and future cost). Then, at this point, it is possible to obtain the water value considering (3.1).

$$\frac{d[ICF]}{d[SE]} = -\frac{d[FCF]}{d[SE]} \tag{3.1}$$

Marginal cost of thermal generation ($/MWh)

Water value ($/MWh)

Moreover, when there are a lot of hydros in the same river, i.e. there is a cascade of hydros, it is also relevant to consider the coordination of the operation concerning the sequential use of the potential energy stored in the reservoirs installed in the same water basin. This issue is illustrated in Figure 3.11. If the operation of these three hydros is centrally coordinated, the optimal decision is, first of all, to generate using the upstream hydro in order to release water ($Q_1$). Then, this water will reach the second hydro, raising the level of this reservoir ($h_2$). A higher level means a higher potential energy for the same amount of mass. Ultimately, this process can be repeated throughout the cascade in order to obtain a higher efficiency of the energy resources.

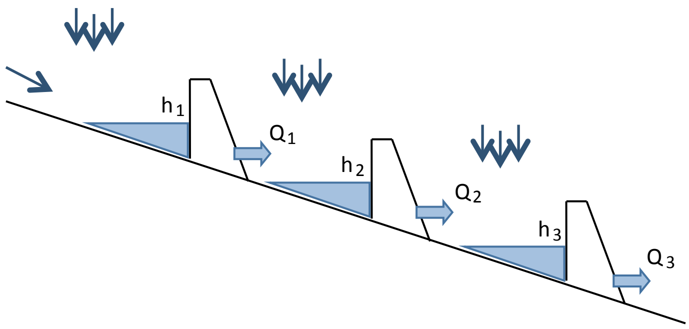


**Figure 3.11 – A cascade of hydros in the same river**

Besides these issues, the Brazilian hydrothermal power system also displays an energy complementarity among its geographic areas. Just concerning the renewable energy, these resources are roughly distributed throughout the country as follows: the Northern area (surrounding the Amazon area) has a large hydro potential; in the Northeast there is a lot of wind, sun, biomass and a few strategic hydros; the Midwest and Southeast present a lot of hydros and biomass, and the Southeast is known as the largest “water tank of the country” since it concentrates many reservoirs with multiannual capacity; finally, the South is characterized by some relevant hydros, but with a more irregular hydrological regime pattern.

Moreover, it is interesting to note that when it is raining (i.e. high hydro production) in the South, Midwest and Southeast, it is the dry season in the North and Northeast. During the dry season it is the harvest time (thus, biomass can be used to produce electricity), and it is when wind is stronger available (which means more electricity coming from the wind farms). As a result, it is required an analysis that considers transmission constraints and the energy complementary regimes between these areas.

As a consequence, the dispatch is centralized and the optimal dispatch problem of the Brazilian hydrothermal power system is currently solved through a stochastic dynamic programming and a linear programming models. In practical terms, this solution is implemented by following two main mathematical models [CEPEL, 2013]:

- NEWAVE (Strategic Model for Hydrothermal Generation by Equivalents Subsystems), which uses stochastic dual dynamic programming to perform studies up to five years ahead with an aggregated representation of hydropower plants (equivalent reservoirs) in order to determine the share of hydro and thermal generation that minimizes the expected value of the operation cost; and
- DECOMP (Medium-Term Operation and Planning), formulated as a linear programming problem to represent individually physical and operational constraints of the thermal and hydropower plants in order to determine the generation target for each power plants for the next 12 months.

The water value in the hydro reservoirs is the main variable, and it is set by the ONS examining, among other issues, the forecasted hydrology, the water levels in reservoirs and demand expectations. Figure 3.12 schematically represents the main inputs and outputs of these models.

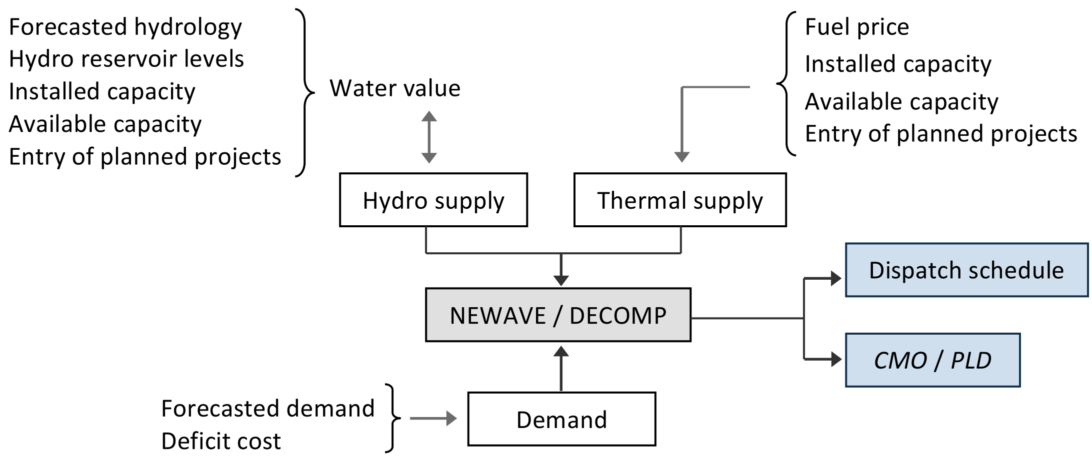


**Figure 3.12 – Dispatch order and short-term price formation, adapted from [Rosa *et. al.*, 2013]**

The NEWAVE model is run once a month, while the DECOMP model is run every week. It is from this "chain of models" (since the NEWAVE and DECOMP are run in a sequential way) that the dispatch of the power plants under operation in Brazil is obtained. In other words, it is through this procedure that the ISO decides the output of the power plants under operation and connected to the National Interconnected System. As can be noted, the dispatch is done without considering the closed contracts.

Beyond the dispatch schedule, these software codes also provide the "Operational Marginal Cost" (in Brazil known as *CMO*), which represents the variable cost of the most expensive dispatched generation resource to supply the next load increment. Then, the Brazilian short-term price, well-known as *PLD* (Price of the Differences Settlement), is determined weekly based on the *CMO* calculation. The difference between the *CMO* and the *PLD* is due to the fact that, for the *PLD* calculation, internal submarket constraints and possible test generations are removed from the computation models. Additionally, in the *PLD* calculation the maximum and minimum short-term price limits set annually by ANEEL are also considered.

Prices in each area are weekly computed for three load steps (heavy, medium and light[32]) for each submarket (North, Northeast, Southeast/Midwest and South). In the last 5 years, weekly prices have been equal in the four submarkets for 55% of the time [Rosa *et. al.*, 2013]. The major transmission constraint is between Southeast/Midwest and North/Northeast. Roughly 75% of the time prices are equal between South and Southeast/Midwest and between North and Northeast.

Additionally, it is also relevant to remark that the centralized dispatch carried out by ONS is done considering a Mechanism of Risk Aversion (MRA). In the model currently in use, the problem of optimizing the hydrothermal dispatch was designed using the minimum operating cost criterion. Its goal is to obtain an operation policy that minimizes the expected value of the thermal generation and possible load shedding. This operation policy is obtained after the evaluation of a given set of possible scenarios of future inflows (2,000 scenarios in the NEWAVE program simulation). The impact of more severe hydrological scenarios on the operating policy is indirectly considered through their contribution to the expected value (average) of the total operating cost. As a result, there is no guarantee of protection regarding the events originating the largest regret that correspond to the occurrence of (very dry) critical hydrological series and violation of the desirable level of security [CPAMP, 2013].

So, the MRA (Mechanism of Risk Aversion), called in Brazil by Conditional Value at Risk (CVaR), is included in the algorithms [CNPE Resolution 3/2013]. This MRA aims at incorporating the cost of the most critical scenarios in the calculation of the operating policy jointly with the procedure regarding the minimization of the total operating cost. In the end, this MRA can represent more thermal generation dispatch in order to save water for use in the future, when it is likely to have critical inflows in the watershed.

To conclude, it is not the market through the interaction among its participants that determines the electricity short-term price, but computational programs that value the present electricity cost considering, among other issues, future scenarios of water inflows and a mechanism of risk aversion to protect the system against severe hydrological series.

Since the short-term price is a result of computer programs, theoretically, this endogenous price would be efficient and immune to market failures, particularly the use of asymmetric information and market power [Santana, 2004]. However, in 2007 and 2011 relevant problems related to inconsistencies in these models were detected, causing a large impact on the electricity sector. Moreover, the transparency related to the programs is also a constant concern because the software codes have intellectual property rights and, therefore, they are unknown by market participants and authorities[33], which induces some instability in the sector.

[32] Heavy, medium and light load steps mean, respectively, hours of the day where there are peaks in demand, average consumption; and low consumption.

[33] The market participants and authorities know the general algorithm and mathematical formulation behind these software, but not precisely how they were written, i.t. the lines of their codes.

### 3.2.4 The Mechanism for Reallocation of Energy (*MRE*)

Table 2.1 included in Section 2.3.1 of Chapter 2 addresses the conciliation between the dispatch and commercial commitment considering the four electricity industry structures described in that section. In the cell related to Model 2 (the Single Buyer Model linked with the Brazilian case), it was mentioned that it is needed a mechanism to share the risk associated with the fact that market participants must uphold their closed contracts by physical generation, but it is the ISO that decides their outputs without considering their contracted energy. This section is dedicated to present and discuss the mechanism currently in operation in Brazil to address this issue: the Mechanism for Energy Reallocation (*MRE*).

The *MRE* was established by the Decree 2655/1998, and its articles 20 to 24 state that:

- The rules of the market operator shall establish the *MRE*, and hydro stations will participate in this mechanism with the purpose of sharing the hydrological risk between them;
- The accounting rules are related to the redistribution of credits and debits between the hydros within its coverage, and they should take into account the existence of market zones (i.e. "submarkets");
- A share of the physical guarantee will be allocated to each hydro station using a compensation mechanism of the energy that is actually generated;
- The physical guarantee of each hydro will be reviewed every five years, or when significant events occur;
- The energy transfers between the *MRE* participants will be subjected to the application of a charge, called "Energy Optimization Tariff", to recover incremental costs incurred in the operation and maintenance of power plants and also compensate from a financial point of view the use of water resources; and
- The risk of unavailability of hydropower generation will be undertaken individually by participants, and therefore it is not covered by the *MRE*.

Regarding the mentioned "hydrological risk", it must be previously assumed that the dispatch is centralized. As the ONS will dispatch the system as shown in Section 3.2.3, the risk of not be dispatched is, in this sense, linked with the efficient and optimal use of the energy resources. Thus, the hydrological risk must be seen as associated with energy optimization and with the efficiency of the *SIN* regarding the centralized dispatch of the ONS.

In Brazil, due its large territorial dimensions, there are significant hydrological differences between regions. The dry and wet periods do not coincide, i.e. there will be periods with low water inflows in certain water basins while in other areas of the country it is the season of high water inflows. Hydros in the water scarcity area will be compensated by the others larger water abundance, and later on these periods will be reversed. Besides, a centralized coordination brings the gain of efficiently use the water stored in cascades of hydro stations in the same river. Then, the *MRE* works like a "condominium of hydros" since they are individual owners (hydro facilities) that share a common good: water.

However, the same centralized dispatch that brings an improved coordination and efficiency to the power system also prevents the agents from participating in the decisions of how much they will generate to meet their contracts. As it was presented in Section 3.2.1, large hydros participate in public auctions in the quantity type auctions, and by doing so they commit to deliver a certain amount of electricity (MWh). Once generators are passive in the centralized dispatch process, the *MRE* is the mechanism for sharing the risk associated with this market design.

So, the *MRE* is a financial mechanism that aims at promoting the sharing of risks associated with the centralized dispatch that is performed by the ONS. This dispatch aims at promoting the optimization of the hydrothermal system and to ensure the efficient use of the energy resources. The goal of the *MRE* is to ensure that all its members receive their "physical guarantee" level regardless of their actual level of energy production, provided that the total generation of the *MRE* participants is not below the total physical guarantee of the system. In addition, the level of physical guarantee considered here is the value that comes from the seasonalization and modulation process (as addressed in Section 3.2.2).

All generators receive their contractual payment because they sell the "physical guarantee assigned to them", and not because they sell the "actual electricity produced by them". Then, in each accounting period, the *MRE* reallocates energy, transferring the surplus generated by those that produce beyond their physical guarantee to those that produce below [CCEE, 2014e].

In order to provide an illustrative case, let's suppose that there are only two submarkets (submarket N and submarket S), and that four hydro stations participate in the *MRE* as shown in Table 3.5 and Figure 3.13.

**Table 3.5 – Numerical example of the *MRE***
(in MWh x 1.000)

| Hydro | Submarket | Seasonalized physical guarantee | Own production | Deficit (-) or Surplus (+) |
|---|---|---|---|---|
| Hydro A | N | 50 | 59 | + 9 |
| Hydro B | N | 40 | 18 | - 22 |
| Hydro C | S | 20 | 64 | + 44 |
| Hydro D | S | 30 | 14 | - 16 |
| Leftover energy or secondary energy = | | | | + 15 |

The allocation of energy from hydros with surplus generation regarding their physical guarantee to those who present generation deficit is primarily made among hydros located in the same submarket. In this example, this can be observed in the first step of the process: in Submarket N, Hydro A gives 9 units to Hydro B (which had a deficit equals to 22); and in Submarket S, Hydro C gives 16 units to Hydro D (allowing to recover all deficit of Hydro D).

Then, after applying this procedure, the remaining surplus (Hydro C still have 28 surplus units of energy) is given to hydros located in deficit submarkets until completing their levels of physical guarantee: the second and the third steps show that, from the 28 surplus units of energy from Hydro C, 13 units were transferred to Hydro B in order to fill its equivalent amount of physical guarantee.

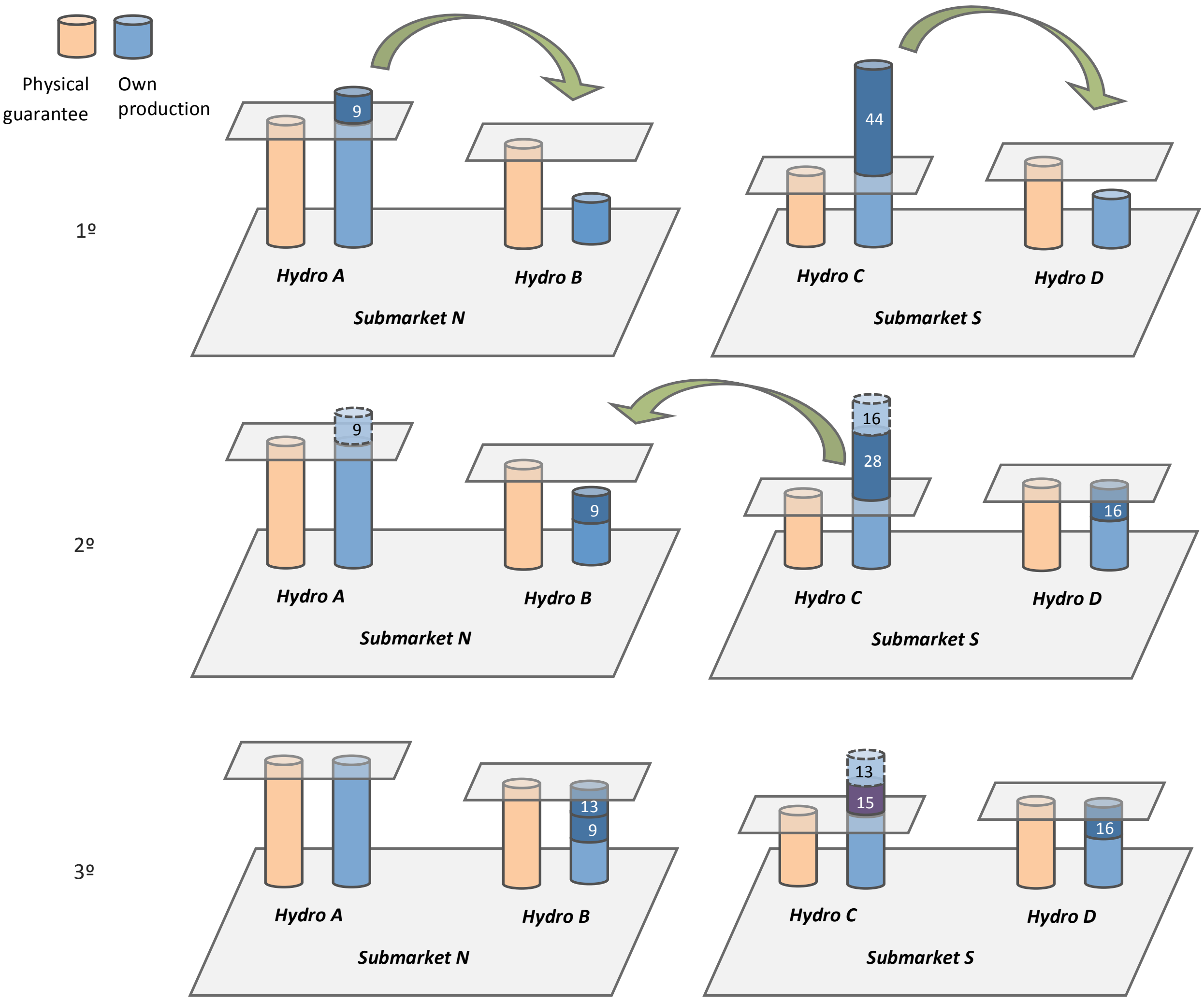


**Figure 3.13 – Representation of MRE process (first steps), adapted from [CCEE, 2014d]**

Thus, now all hydros have at least the same amount of their physical guarantee. However, there are still 15 extra energy units in Hydro C. This happens whenever the total production of electricity of *MRE* hydros is higher than the total physical guarantee of the *MRE* hydros. This surplus is named “secondary energy” and it is allocated to all members of the *MRE* in proportion to their physical guarantee, as shown in Figure 3.14.

Nevertheless, if the total generation of the *MRE* is less than the total physical guarantee of the system, it is promoted an apportionment of the energy produced so that everyone will have an equivalent percentage deficit (illustration presented in Section 3.3.3). This reduction is accomplished through the application of an adjustment factor. In situations like that, usually associated to critical hydrologic periods spread in different geographic areas of the country, the *MRE* is not able to cover the risk of generators having to buy electricity in the short-term market at *PLD* to complete the energy committed by their contracts.

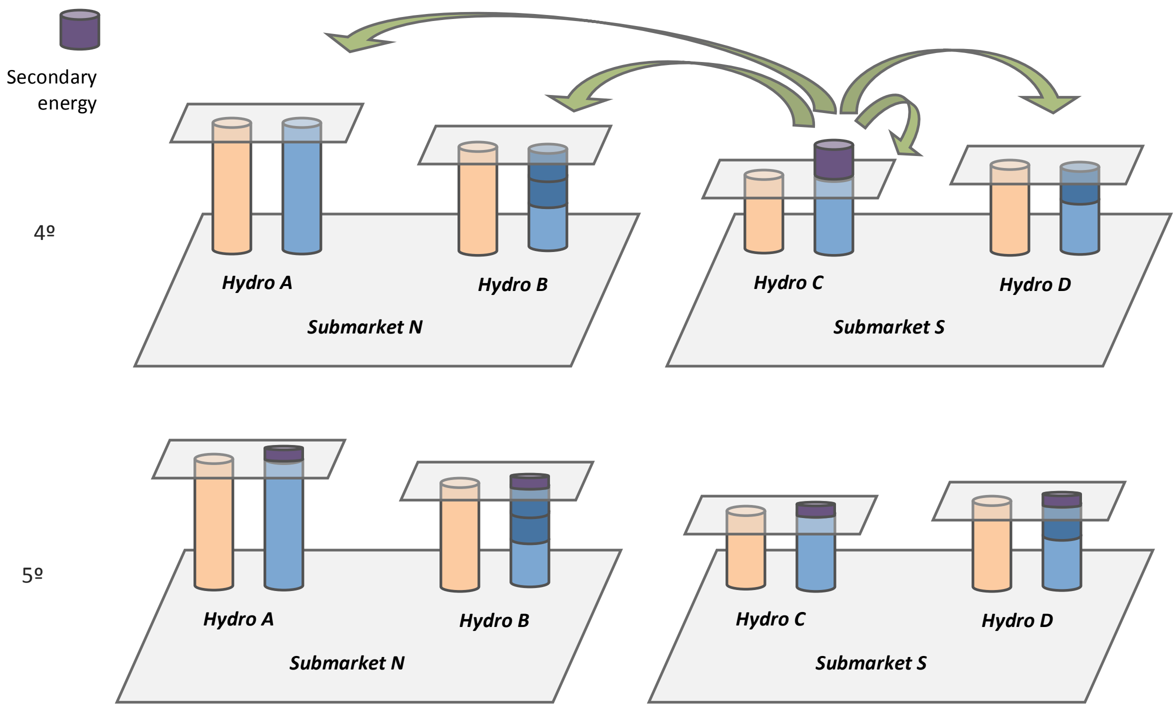


**Figure 3.14 –Representation of MRE process (secondary energy), adapted from [CCEE, 2014d]**

The electricity production allocated through the *MRE* is valued by a tariff called "Energy Optimization Tariff" (in Brazil, *TEO*). This tariff, expressed in R$/MWh, is established by ANEEL and is used to financially compensate hydros that provide energy to the MRE. So, the *TEO* is paid by hydros that become net recipients of energy into the MRE, both to cover their physical guarantee or related to the allocation of the secondary energy [CCEE, 2014d].

Besides that, when the allocation of energy occurs between submarkets with different *PLDs* it should be also considered in this transaction the difference between prices. So, if the *PLD* of the submarket where the energy comes from is higher than the *PLD* of the submarket where the hydro having the deficit is located, this hydro will have to pay also the difference between these two prices multiplied by the amount of energy allocated to him. This is known as a "negative exposure to the price difference between submarkets".

### 3.2.5 The short-term market (*MCP*)

The Brazilian short-term market (*MCP*) takes place after the dispatch of the ISO. Unlike other market designs addressed in Chapter 2 (notably regarding the examples presented for Models 3 and 4), the Brazilian short-term market is not the marketplace where generators are active through a self-dispatch procedure nor can generators influence the dispatch through their bids. Ultimately, this short-term market is not an environment where market participants can engage in short-term trades on their own account, as there is no short-term declaration of intent.

So, contrasting with other short-term markets, the *MCP* is a mechanism to settle differences between the amounts of electricity committed by contracts and those amounts of electricity that each agent ends up providing / receiving. These differences are illustrated in Figure 3.15 (red box) and they must be automatically purchased or sold in the *MCP* during the settlement process of the CCEE.

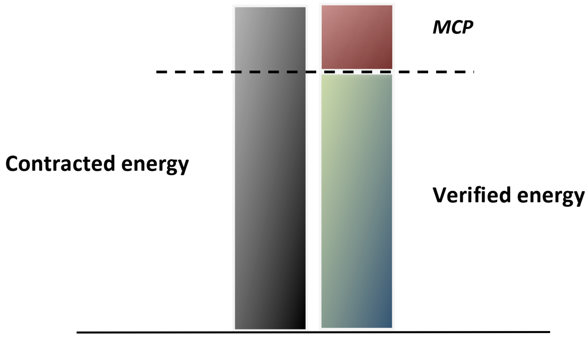


**Figure 3.15 – Traded energy in the Brazilian short-term market (*MCP*)**

In the scope of the Brazilian electricity market, it is important to clarify the meaning of the "verified energy" and the "contracted energy".

As explained in section 3.2.4, through the *MRE* it can be added to the "own production" "an extra energy". Thus, the verified energy is the sum of the own production and total amount resulting from the *MRE* (equation 3.2).

$$\textbf{Verified energy} \ = (own\ production) + (energy\ allocated\ from\ the\ MRE) \qquad (3.2)$$

Moreover, it can be noted (as it was discussed in Section 3.2.3) that the "own production" is strongly influenced by the ISO dispatch, since the scheduled production comes from the ONS centralized dispatch. The small difference between the own production and the scheduled production is usually related to the dynamic of the real time operation of the power system. Accordingly:

$$\textbf{Own prodution} \ \approx (schedule\ production\ by\ the\ ISO) \qquad (3.3)$$

On the other hand (left part of the Figure 3.15), the contracted energy is the monthly and hourly amount defined in the seasonalization and modulation process (analyzed in Section 3.2.2). Thus:

$$\textbf{Contracted energy} = (closed\ contracts\ afther\ the\ seasonalization\ and\ modulation) \quad (3.4)$$

Finally, the exposed position regarding the short-term price is the difference between the verified energy and the closed contracts as given by (3.5).

$$\textbf{Exposed position} \ = (verified\ energy) - \ (contracted\ energy) \qquad (3.5)$$

In order to put all these elements together, let us now consider Figure 3.16[34].

[34] In Figure 3.16 it wasn't allocated the secondary energy, but the exactly amount to fulfill the required physical guarantee level. If it is allocated secondary energy, the verified energy will be higher than the physical guarantee.

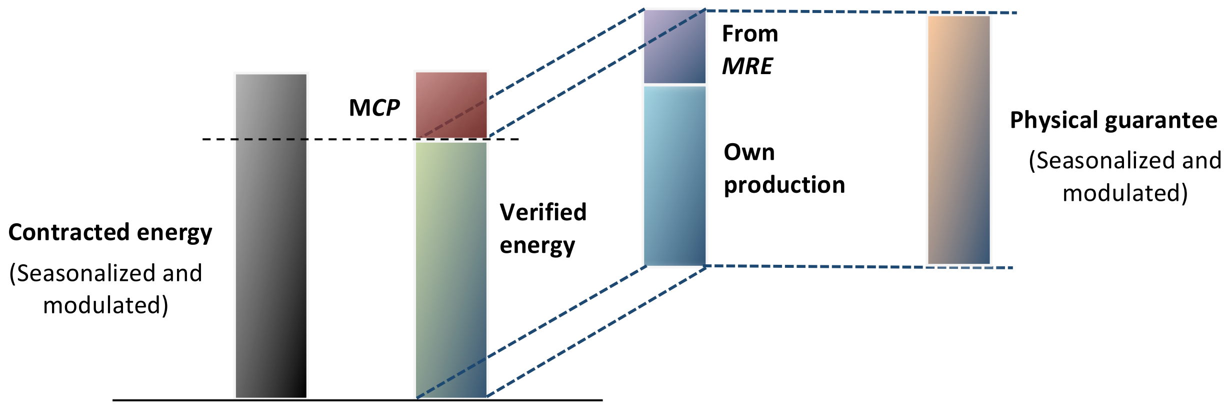


**Figure 3.16 – Traded energy in *MCP*: negative exposition**

The *MCP* is the last step of a series of events. To provide an overview of this process, the sequence of events will now be exemplified:

- After signing the *CCEAR* (an *ACR* contract) and when the power plant becomes available to produce electricity, the seasonalization of the contracted energy and the seasonalization of the physical guarantee are conducted;
- These seasonalization procedures are repeated once a year, typically in December, and their results are applied for the entire next year. First, it is executed the seasonalization process of the *CCEAR*s and afterwards the seasonalization of the physical guarantee. The modulation for both the *CCEAR* and the physical guarantee is automatically performed every month according to the commercialization rules of the CCEE in order to establish the value per load steps (set of hours in the 24 hours of the day);
- The power plants are dispatched by the system operator (ONS) on a weekly centralized basis in order to optimize the hydrothermal system and to use efficiently energy resources. The dispatch and the PLD are  established for each load step of the day;
- The *MRE* takes place: if the own production of one hydro is less than its physical guarantee (which is calculated to represent, in the long term, the amount of electricity that can be continuously produced), the hydro will receive energy from other stations that produced more. In other words, the *MRE* will be allocate energy to this hydro station;
- The own production plus the energy allocated from the *MRE* is equal to the "verified energy". The "verified energy" is then compared with the "contracted energy", and the resulting exposition is settled in the short-term market (*MCP*) at the short-term price (Price for Settlement of Differences - *PLD*). This settlement is performed for each agent on a weekly basis considering the three load steps of the day of the week (heavy, medium, and light).

If the power plant has less verified energy than the contracted energy, this exposition is negative, which means that the generator has to buy this difference in the short-term market (*MCP*); otherwise, the exposition is positive and the generator will inexorably have to sell this difference in the short-term market (*MCP*). As the first situation is illustrated in Figure 3.16, the second one is characterized in Figure 3.17. Then, all trades (purchases and sales) in the *MCP* are valued by the short-term price, or the *PLD*, as it is also entitled in Brazil.

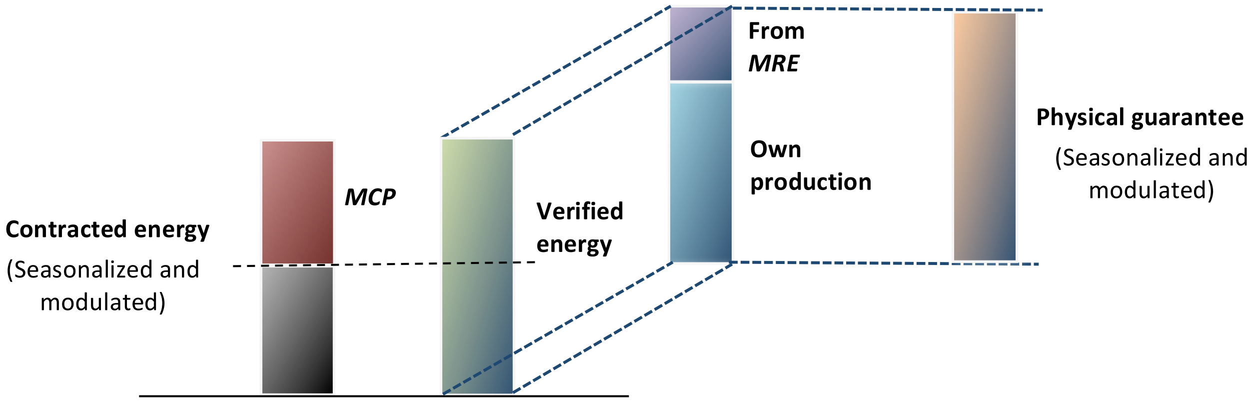


**Figure 3.17 – Traded energy in the *MCP*: positive exposition**

As a result of this market design, the *MCP* acts as a "mechanism to settle differences" rather than a true market. The *MCP* cannot be seen as a (short-term) market once the (short-term) transactions in the *MCP* are not a result of (short-term) offers made by market agents. Market agents do not share a common platform to make their short-term declaration of intent.

Moreover, the price that values these transactions (*PLD*) is not the result of the interaction between market participants, but it results from the application of a chain of software based on dynamic and linear programming, which is operated by a third party. In summary, it would be a short-term market if, in this environment, market participants meet each other in order to negotiate electricity and close agreements in the short-term according to their own will.

As previously presented, all consumption (from the *ACR* or *ACL*) has to be linked with a contract and all contracts have to be supported by a physical guarantee. Generators can sell in the *MCP* part of the physical guarantee not committed by contracts, but as a rule they prefer to sell the vast majority of their physical guarantee through long or medium-term contracts. In addition, all such contracts have to be registered in the CCEE in order to measure, account and settle the aforementioned expositions.

Figure 3.18 synthesizes relevant points. Once all consumption has to be ex-ante contracted, and contracts have to be physically backed, structurally the Brazilian market was designed to have no mismatches between the "computed long-term production capacity (i.e. physical guarantee) and the foreseen consumption". As a consequence, it remains to the *MCP* to deal with the differences that occur due to the mismatch between the monthly verified energy (for both the generators and consumers) and contracted energy.

Then, to bring Section 3.2 to a close, and having in mind the Brazilian market results and the physical operational of the power system, Table 3.6 shows the types of contracts from both the *ACR* and the *ACL*, and briefly explains how dispatch procedure is carried out by the system operator (ONS) and the exposed positions are settled by the market operator (CCEE).

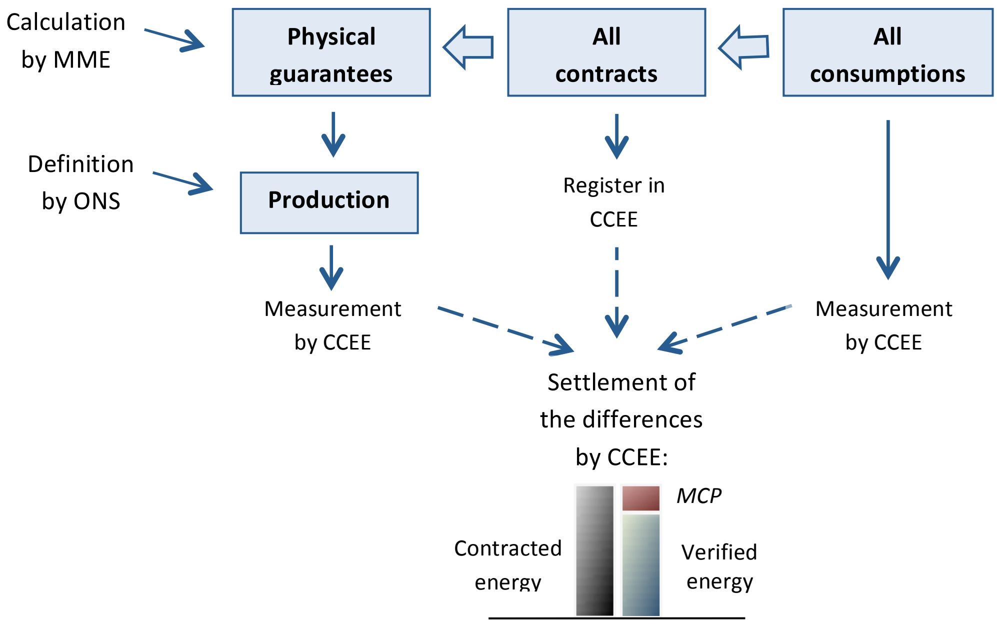


**Figure 3.18 – An overview of the commercialization processes**

**Table 3.6 – The *ACR* and *ACL* markets, the dispatch procedure and the *MCP***

<table>
<tr><th>ACR - Regulated Contracting Environment<br>(Model 2)</th><th>ACL - Free Contracting Environment<br>(Model 4)</th><th>ISO dispatch procedure<br>(Tight pool)</th><th>Brazilian short-term market (MCP)<br>(Imbalance mechanism)</th></tr>
<tr><td colspan="2">Types of contracts involved:</td><td>How are generators dispatched by the ONS?</td><td>How are exposed positions settled by the CCEE?</td></tr>
<tr><td>• CCEAR (Contract for Electricity Trading in the Regulated Environment)</td><td>• CCEAL (Contract for Electricity Trading in the Free Environment)</td><td rowspan="7">• ISO knows installed capacity, availability and fuel cost of generators.<br><br>• ISO also knows the predicted consumption of the Discos.<br><br>• ISO does weather forecasts to estimate the river inflows and the affluent natural energy of the hydro stations.<br><br>• ONS runs software based on stochastic dynamic and linear programming to establish the dispatch and the PLD.</td><td rowspan="7">• All closed contracts (in both ACR and ACL) have to be recorded in CCEE.<br><br>• CCEE measures the amounts actually produced / consumed by each agent.<br><br>• MRE is applied for participants in this mechanism.<br><br>• Differences between the contracted energy and the verified energy are accounted.<br><br>• Exposed positions are valued using the PLD.</td></tr>
<tr><td colspan="2">• CER (Contract for Reserve Energy), signed between CCEE and seller agents</td></tr>
<tr><td colspan="2">• CONUER (Contract for Use Reserve Energy), signed between CCEE and consumption agents</td></tr>
<tr><td>• Contracts for Distributed Generation</td><td rowspan="4">• CCEI (Contract for Purchase Encouraged Electricity)</td></tr>
<tr><td>• Contracts of Adjustments</td></tr>
<tr><td>• Contracts of PROINFA (Program of Incentives for Alternative Electricity Sources)</td></tr>
<tr><td>• Contracts of Itaipú hydro</td></tr>
</table>

## 3.3 Concerns about efficiency, security and flexibility

This section is dedicated to discuss three specific topics intrinsic relevant to the thesis:

- **Efficiency** in the use of the energy resources, mainly considering the dichotomy between the centralized and decentralized dispatch;
- **Security** of supply achieved in Brazil through the long-term contracting via public auctions, and the requirement that all contracts must be physically backed; and
- **Flexibility** to enable generators to uphold signed contracts, either through their own production or through the *MRE*, and then deliver the ex-ante contracted quantities.

### 3.3.1 Efficiency of energy resources: The centralized dispatch

[Santana, 2004] points out that the electricity industry has such characteristics that reasonable efficiencies can be achieved through adequate coordination. Extensive discussion is conducted whether such coordination can be sought through the market or through the hierarchical approaches. In this case, the approach via market demands to design a model where the market price and the dispatch comes from the market participants' interactions, as it happens in day-ahead market with price and quantity bids are offered by generators. In other hand, hierarchical approaches mean that a centralized dispatch takes place, as it happens in Brazil. In this case, there is no price bid by hydros. Instead of that, it is computed the water value as shown in Section 3.2.3.

So, in order to compare the Brazilian case with a similar power system in terms of large hydro penetration, it is worth examining the New Zealand electricity market. Despite the total installed capacity in New Zealand (10 GW) [MBIE, 2012] is quite different from Brazil (142 GW) [ANEEL, 2015], both power systems are similar in terms of the share and importance of hydro generation. New Zealand has around 60% of the produced electricity from hydropower plants[35] [New Zealand System Operator, 2014] and Brazil, during the years 2012 and 2013, also produced around 60% of the electricity from hydros [ONS, 2014d].

The New Zealand electricity sector also went through a liberalization reform during the 80s and 90s. This reform was fuelled by the need to reduce the government budget deficit, a desire to see state-owned business activities set on a more commercial basis, and the use of market-based mechanisms rather than politically driven state planning [Evans & Meade, 2005]. Since 2004, the New Zealand electricity sector operates as a compulsory market pool, in which all generated and consumed electricity is traded, and where trading is developed by bids (supply and demand) for 48 half hour periods (the trading periods) over 224 pricing nodes [Philpott et. al., 2010].

Nevertheless, some authors suggest that running certain electricity sectors as a centrally planned monolith would yield superior outcomes because it is under "complete" control by one "person" who has access to all relevant information about factors affecting demand and

[35] From the remaining 40%, about 20% is produced by thermal power plant, 15% from geothermal power plant, and 5% from wind and co-generation.

supply [Evans & Meade, 2005]. On the heels of this centralized approach, [Philpott et. al., 2010] describe an empirical study on the extent of productive inefficiency of the New Zealand wholesale electricity market. In this study, the authors attempt to quantify production efficiency losses by comparing market outcomes with a counterfactual centrally planned operation.

These authors also agree that, unlike markets consisting solely of thermal power plants, markets with hydros have an inter-temporal nature arising from the fact that the energy (water) can be stored for later delivery. This feature complicates the decision making process of hydros as the computation of the marginal cost of releasing water must involve some modeling of the opportunity cost and of the possible shortage costs.

Nowadays, by default, each generating station in New Zealand is treated by the market operator as a separate entity to be dispatched according to its energy offer. However, the inefficiency in the New Zealand wholesale market design is recognized by including an instrument called block dispatch. Under the block dispatch mechanism, after communicating the offers and before conducting the dispatch, generators can rearrange the dispatch amongst their stations on the same river-chain, as long the total energy delivered is the same as that required and stations are geographically close so that the short-term prices assigned to the associated grid nodes are similar enough. Thereby, the block dispatch is designed to provide a desirable hydrological inflow pattern. Additionally, the vast majority of the hydros in the same river are operated by the same generation company[36], what turns this block dispatch scheme more easily applicable.

Although block dispatch affords some degree of flexibility, according to these authors it is essentially an instantaneous process, and the inter-temporal features of the river chain operations are not represented in the single-period market clearing mechanism. This issue corresponds to a new source of inefficiency. Having this issue in mind, [Philpott et. al., 2010] established a counterfactual model that considers a power system with significant hydro generation and which is centrally planned. This counterfactual model was developed considering a recent study based on the Nord Pool system conducted by [Kauppi & Liski, 2008] and on the stochastic dynamic programming technique of [Pereira & Pinto, 1991]. So, this model computes a generation policy that takes in account the future inflow uncertainty, as well as several reservoirs and constraints associated to the New Zealand transmission system.

At that time, three experiments were done. The first one (daily model) associates a daily dispatch under the market model with a dispatch under a centralized approach. Then, the second and the third experiments solve the problem over one week and one year, respectively. As a result, by comparing the counterfactual proposal that supposes that the New Zealand electricity system is centrally controlled with the actual market based dispatch, they found that the central control can exploit some flexibility in transferring water between periods. In the following, the numerical results of this study are presented:

[36] This is not what happens in the Brazil, where there are several different owners in the same river-chain.

- Daily model: Considering the results for Monday June 20, 2005, and given the costs of thermal fuel, the thermal cost in the central plan is (NZ) $ 1,547,273 as compared to (NZ) $1,580,918 for the market model. This represents an inefficiency estimate of (NZ) $ 33,645, or about 2.1%. The inefficiency estimate does not change significantly if it was computed for other days in this week. The inefficiency values range from 1.9% to 2.9% with an average of 2.3%.
- Weekly model: The central plan approach shows that some flexibility in transferring water between days can be exploited. The overall savings in the observed week (June 18-June 24, 2005) is (NZ) $ 729,433, which corresponds to 6.8% of market fuel cost. To see if these weekly savings are also present in other weeks, the computation for each week of 2005, 2006, and 2007 was conducted and, in average, the difference between the total fuel costs of the weekly central plan and the market in percentage is 8.3%.
- Yearly model: The results show a trajectory of water storage for the central plan more extreme than the market trajectory. In the winters of 2005, 2006 and 2007, the central plan doesn't use the more expensive thermal power plants as much as the market plan. There is an extra 386 GWh of water stored by the market at the end of 2007 as compared with the central plan. The yearly centrally-planned policy incurs in less fuel costs than the market. For 2005, 2006 and 2007, the saved fuel costs are, respectively, 16.0%, 13.4%, and 14.6%.

As observed, a higher fuel cost from the market comes from differences in the merit order arising from generators marking up their short-run marginal costs unevenly in the market (e.g. resulting in the dispatch of high-cost thermal power plants rather than less expensive stations). Based on the examination of the offer bids, hydro and thermal power plants appear to alter their offers over the day, in contrast to a marginal cost based offer that should not vary in the short term. Such behavior could be interpreted either as generators bidding strategically, or bidding to meet short-term inter-temporal constraints.

Generators make offers and are dispatched each half hour. So the offers they submit in each half hour are the only mechanism that they have to build a varying generation plan to comply with their own constraints over the day. Thus, the authors advocate that some of the inefficiency could arise as an artifact of the half-hour market design, rather than reflecting strategic offering behavior. So, they concluded that some savings of the central plan are related to the capacity to anticipate inflows and shift hydro generation to avoid spilling or shortages, features that are not apparently obtained by the market solution.

In the end, it becomes clear that, in the case of a power system having a large share of hydro generation, the coordination of the water stored in the reservoirs is a relevant issue that must be addressed somehow. Since the goal of the dispatch is to achieve the welfare maximizing for the system as a whole, either through the market or through a centralized control, the results of [Philpott et. al., 2010]'s analysis suggest that the centralized dispatch yields more efficient solutions.

### 3.3.2 Security of supply: The long-term contracting physically backed

This section is devoted to study the market design adequacy in the long-term, a discussion that was initiated in Section 2.3.2. However, here this issue is analyzed focusing on the Brazilian electricity market and taking into account data from this market. For this reason, and in order to oppose to the current long-term contracting scheme, the Brazilian case will be investigated as if it was operated entirely based on a short-term market.

Therefore, the same concerns already mentioned in Section 2.3.2 should be in mind. Considering the short-term market: Are there in the market design enough incentives to provide adequate investment? Will the response of generators regarding the short-term prices come in the form of new installed capacity? Should a capacity mechanism be added to the market design?

As explained earlier, the Brazilian short-term price, *PLD*, is calculated for four submarkets (South, Southeast/Midwest, Northeast and North) and it is set on a weekly basis for three load steps (heavy, medium and light). Moreover, the *PLD* has maximum and minimum limits that are established by regulation. For the year 2014, these limits are 822.83 R$/MWh and 15.62 R$/MWh [ANEEL Approving Resolution 1667/2013]. Figure 3.19 presents the historic *PLD* data obtained from 2001 to 2014 [CCEE, 2014c].

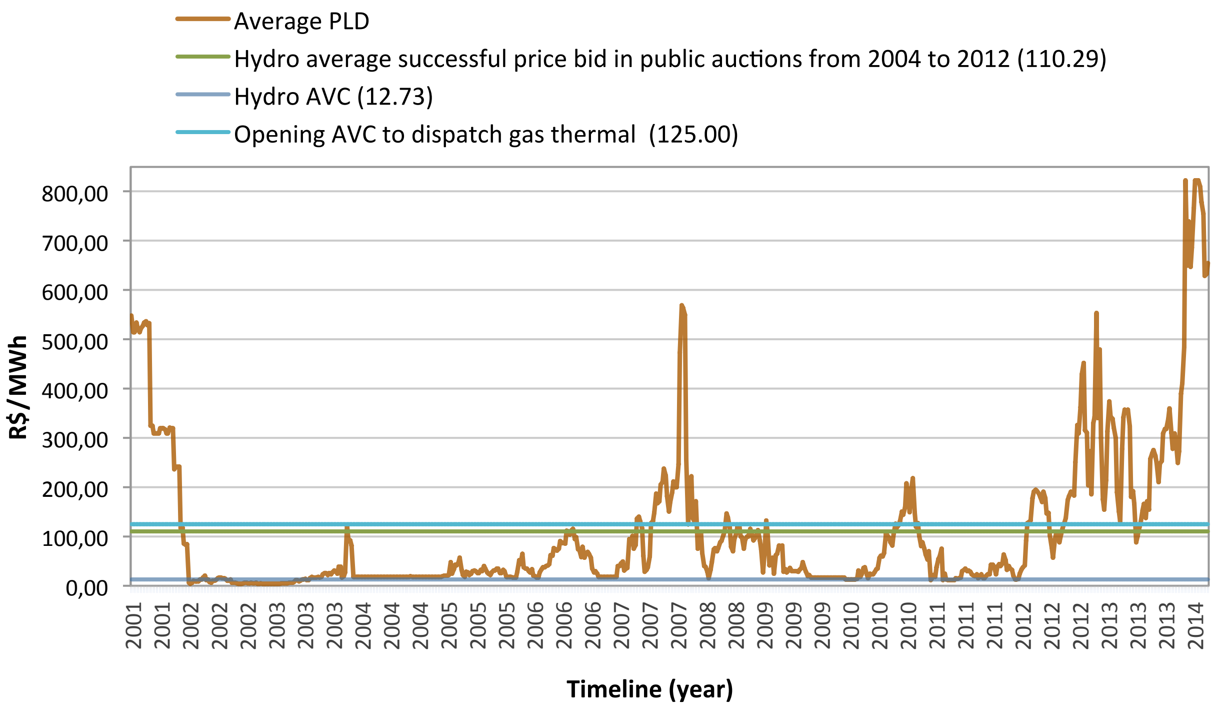


**Figure 3.19 – *PLD* historic data: from 2001 to 2014**

The value of the *PLD* displayed in this figure results from a weighted sum of the values obtained for the four submarkets and for the three load steps. Furthermore, this figure also indicates the hydro average successful price bid that came from public auctions carried out from 2004 to 2012 in Brazil (110.29 R$/MWh) [CCEE, 2014c], and the hydro Average Variable Cost (AVC) computed considering data from the Brazilian hydros with installed capacity larger than 100 MW (12.73 R$/MWh) [ANEEL, 2012][37]. In addition, the AVC starting point to dispatch the gas thermal power plant can be considered at to 125 R$/MWh[38] [ONS, 2014].

Throughout all this period, the *PLD* is above the hydro AVC (12.73) for almost 90% of the time. However, *PLD* is higher than the hydro average successful price bid (110.29) just for 30% of the time. This price bid is the PPA contract price, thus, at the level of 110.29 R$/MWh this price is expected to recover both the hydro Variable Cost (VC) and the Fixed Cost (FC). In other words, it can be also perceived as the hydro Average Total Cost (ATC). Finally, when *PLD* crosses the line of the AVC related to first dispatched gas thermal power plants (125.00), gas units start to be dispatched, and a proportional amount of water is saved in the reservoir. As it can be observed from Figure 3.19, during most of the time the demand is supplied primarily by hydro.

Nowadays the hydroelectricity represents around 60% of the total installed capacity, nevertheless, historically more than 85% of the electricity produced in Brazil comes from hydro generation. Taking into account this amount of hydros, the *PLD* calculation captures the preference for use water to supply the demand rather than thermoelectric stations, and this allocates the *PLD* at low levels for long periods. In a scenario where all hydros are trading electricity in the short-term market, some questions can be raised: Is the *PLD* capable of recovering both their VC and FC? Is the *PLD* giving effective signals for the construction of new power plants?

The hydros average successful price bid value (110.29 R$/MWh) is the value associated to the generators that offered successfully bid in the public auctions during 2004-2012 in order to sign a PPA. These are auctions of the quantity type auctions which means that these generators will not receive any availability payment. Thus, the price bid value should be enough to recover both the FC (basically, costs concerning civil works and electromechanical equipment, debt burdens and return on own capital) and VC (e.g. operational and maintenance cost, transmission system access cost, charges and taxes) over the contract period during which the power plant will be operating.

The statement that 110.29 R$/MWh, on average, recovers the total cost of the project during the period where generator has the concession to produce electricity is corroborated by the analysis of the price cap defined for the public auctions. This analysis was accomplished by the Brazilian Federal Court of Auditors (TCU) and it considers all elements necessary to compute a fair price cap (e.g. analysis of the consistency of the investment costs, and analysis of the project economic viability). The competition in the public auctions takes place after the analysis of the price cap.

[37] Recently, the Brazilian Government gave a referral to the issue of the renewal of the electricity services concessions through the Provisional Measure 579/2012, converted into the Law 12.783/2013. This norm enables the extension of the concession contracts for a period up to 30 years, provided that, among other conditions, the generator accepts a new remuneration of assets fully amortized compatible with their current Variable Cost (VC). Because of that, a lot of data related to the year 2011 was collected by ANEEL from generators in order to contribute to the process of establishment this remuneration. These were the data used in this section regarding the hydro AVC.

[38] 125 R$/MWh is equivalent to the percentile 20, i.e., 80% of the gas thermal power plants have a AVC higher than 125 R$/MWh.

Through the Court's decision regarding the auction that took place in 2011 for the UHEs Estreito, Castelhano, Cachoeira, Ribeiro Gonçalves, São Manoel, Sinop, São Roque and Cachoeira Caldeirão [TCU Judgment 3005/2011 – Plenary], it can be confirmed that the price caps were calculated considering that the third party capital should finance about 70% of these projects, and the loan should be repayable over 16 years. Regarding the UHE Jirau, hydro presented in the structuring project auctions category that occurred in 2008, 90% of the project was funded by third party capital, and price cap calculation considered that this funding should be amortized over twenty years [TCU Judgment 602/2008 – Plenary]. Consequently, it is expected that the total fixed cost and all annual variable costs are recovered during the entire concession period of hydro power plants operation that typically corresponds to 30 years[39].

In short, this analysis indicated that 110 R$/MWh is enough to recover both the FC and VC during 30 years of hydro operation. On the other hand, the question is whether *PLD*, on average and over 30 years, would be above 110.29 R$/MWh. On average because there will be periods with low *PLD* that will not cover the FC (and sometimes even the VC), but there can also be periods when high *PLD* values that will provide the necessary additional rent to pay FC.

The Brazilian short-term market has been in existence for about fifteen years. For the time being, the *PLD* has an average value equal to 109 R$/MWh. Therefore, it is really close to 110.29 R$/MWh that corresponds to the average hydro price bid. Nevertheless, it should be noted that, since the beginning of the *PLD* historical data, Brazil endured two large energy crises (in 2001-2002 and in 2013-2014) during which the *PLD* remained in extreme levels for a long time, reaching its established regulatory maximum limit during several consecutive accounting periods.

Supposing that from now on there will be more dispatched thermal units and, thus, the *PLD* will be frequently higher than ATC, the question is if the shape of the *PLD* curve will not be a barrier for investments that intend to recover their FC and VC through the short-term prices. At this point, the analysis rests on the *PLD* volatility

In order to characterize the mentioned volatility, we use standard deviation of the sample. The *PLD* standard deviation of the entire set of data has a value of 162.4 R$/MWh. With an average of 109 R$/MWh, a standard deviation equal around 160 R$/MWh originates a big risk to the health of the business, especially regarding the stability of the cash flow. From Figure 3.20 it also can be seen how skew the histogram is. This volatility, indeed, represents a relevant source of uncertainty to the market.

Finally, to answer the question raised earlier in this section, the following main conclusions can be drawn. Despite the hydro average price bid (110 R$/MWh), or the hydro ATC, is close to the average *PLD* (109 R$/MWh), it seems that the high *PLD* volatility (*PLD* standard deviation equal to 162.4 R$/MW) will not provide enough incentives to induce adequate investment to build new power plants. Then, it is possible to conclude that, in order to address the security of

[39] The total concession period for this kind of hydro is usually 35 years, however, the first 5 years are used to build the project, and the remaining 30 for its operation.

supply in Brazil, some capacity mechanisms should be adopted. As discussed in Section 3.1.1, this was done by implementing a long-term contracting scheme in which loads must be fully ex-ante contracted and all contracts must be physically backed.

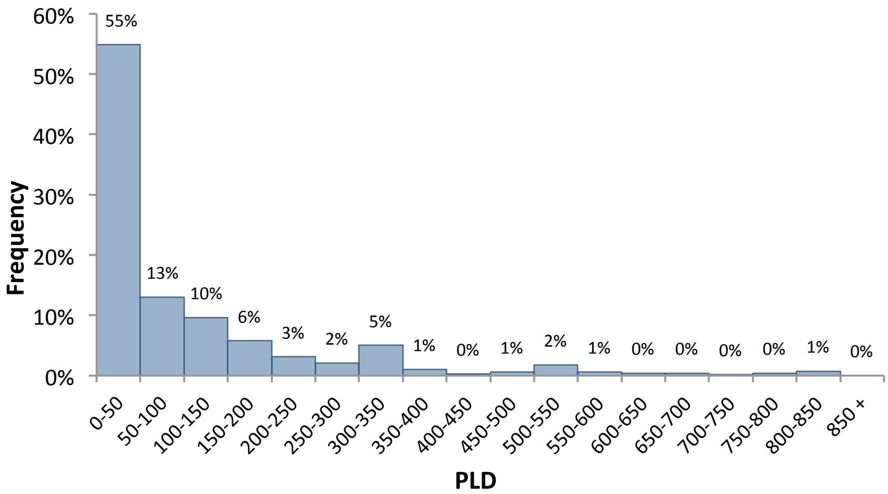


**Figure 3.20 – Histogram of *PLD*: from 2001 to 2014**

Furthermore, despite this long-term contracting scheme, the security of supply in Brazil is also addressed via the dispatch of the ISO, through the mechanism of risk aversion (seen in Section 3.2.3) or via the dispatch out of the merit order authorized by the CMSE, as mentioned in article 2º of the CNPE Resolution 3/2013:

> "Upon a decision of the Monitoring Committee of the Electricity Sector (CMSE), extraordinarily and aiming at ensuring the security of supply and in an additional way to what was indicated by the computational programs, the ONS is authorized to dispatch energy resources or change the direction of the electricity flow between submarkets".

As discussed in Section 3.1.4, a centralized feature regarding the energy supply adequacy in Brazil was strongly embedded within the powers of the institutions that are responsible for the governance of the electricity sector. Within this context, once supported by a study from the system operator (ONS) properly consolidated in a technical note, the CMSE, the body established under the MME (Minister of Mines and Energy) to mainly assess the conditions of the energy supply, can extraordinarily decide for an extra thermal generation dispatch in order to save water in the reservoirs and avoid an energy deficit in the future.

### 3.3.3 Flexibility to endure contracts: seasonalization's windows and *MRE's* straitjacket

In Section 2.3.1 it was discussed the market design completeness, and a special focus was given to answer the following question: How can the dispatch schedule and commercial commitments be conciliated? The analysis regarding the incompleteness of the market design relies on the imperfect coordination between the markets that emerged with the liberalization: forward, future, options, day-ahead, intraday and balancing markets. This sequence of markets is an alternative way to the vertical integrated structure. In this sense, repeated trading of a few simple contracts should approximate a complete market for contingent contracts, and more frequent trading opportunities enhance the completeness of a market [Wilson, 1999].

Nevertheless, Brazil doesn't have a balancing market, neither an intraday, day-ahead, options nor future markets. There are only long and medium-term forward markets (both in the *ACR* regulated contracting environment, which operates like a single buyer model through the national public auctions; and in the *ACL* free contracting environment, operating as the retail competition model). Then, the short-term market (*MCP)* just settles the exposed positions.

Through the seasonalization process, in December of each year generators have to defined for the next entire year the monthly amount of the contracted energy (committed by the forward contracts) and of the physical guarantee (ability to delivery energy in the long-term). So, regarding the temporal flexibility, December corresponds to the unique "window" in which hydros can allocate their physical guarantee to uphold their contracts. In the short-term, there is no way to adjust the amounts previously defined. Thus, considering the market completeness analysis, there is a lack of "trading opportunities".

Moreover, the dispatch is centralized and it is weekly ahead defined by the ISO. Strictly speaking, as discussed in Section 3.2.3, there is no self-dispatch and generators are not allowed to influence the dispatch schedule through bids like it happens in a day-ahead market. Besides, the dispatch is centralized because there is an embryonic need to promote the optimization of the hydrothermal system and to ensure the efficient use of the energy resources, especially concerning the cascades of hydros. So, generators are not that ones who decide their generation levels. They operate their power plants just following the amount of production set by the ISO. For this reason, the *MRE* was implemented*:* a financial mechanism designed to promote the sharing of risks associated with the centralized dispatch.

Notwithstanding, the *MRE* rules are implemented in the settlement process and are applied automatically to all market participants. Thus, this is not endowed with flexibility in a sense that generators cannot deal with it in order to consider their own strategy and risk perception. Due to its characteristic the *MRE* can be viewed as a "strait jacket".

In the next paragraphs two situations that recently occurred in the Brazilian electricity market are discussed. This discussion brings to light some weaknesses of this market design regarding both the seasonalization of the physical guarantee and the *MRE*.

*3.3.3.1 Seasonalization's rules and the MRE's performance in short run*

Due to effects of a new regulatory framework[40] that dealt with the renewal of generation concession contracts, the first situation happened when, the "window" for the seasonalization of the physical guarantee was postponed from December 2012 to February 2013. Given that during January and February 2013 the *PLD* reached high values, some hydros, already knowing the *PLD* value for these periods (which surpassed R$ 500/MWh), concentrated in these two months most of their total annual physical guarantee.

[40] Launched by the Provisional Measure 579/2012, and subsequently converted into Law 12783/2013. This norm is regulated by Decree 7805/2012 and by ANEEL Normative Resolution 514/2012.

Then, considering the rules of *MRE* in force at that time, this strategy generated income for these generators, but a loss of almost R$ 600 million for Eletrobras. Eletrobras is the state-owned that administers Itaipú hydro[41] and the hydros of *PROINFA*[42], and these power plants usually had their seasonalization performed following a flat profile. Moreover, this company holds many hydros that accepted the 2012 renewal of concessions and, according to the ANEEL Normative Resolution 514/2012, article 15, § 1º, their seasonalizations regarding the contracted energy must be automatically performed following the declared Disco load profile.

Using the value of seasonalized physical guarantee to mark the exchange of energy between the *MRE*'s hydros (in order to distribute the energy to support contracts), it happens that agents interfere in the proportion of the *MRE*'s energy that is allocated to themselves as well as to other agents. In other words, in the context of *MRE*, each agent doesn't only depend on its seasonalization, but on what other agents decided. This situations is illustrated in Table 3.7.

**Table 3.7 – The operation of *MRE*: the influence of other participants**
(in MWh x 1.000)

<table>
<tr><th></th><th></th><th colspan="3">Scenario 1</th><th colspan="3">Scenario 2</th></tr>
<tr><th>Hydro</th><th>Own production</th><th>Physical guarantee</th><th>GSF (Generating Scaling Factor)</th><th>Verified energy</th><th>Physical guarantee</th><th>GSF (Generating Scaling Factor)</th><th>Verified energy</th></tr>
<tr><td>Hydro A</td><td>59</td><td>50</td><td rowspan="4">1.107</td><td>55.36</td><td>100</td><td rowspan="4">0.816</td><td>81.58</td></tr>
<tr><td>Hydro B</td><td>18</td><td>40</td><td>44.29</td><td>40</td><td>32.63</td></tr>
<tr><td>Hydro C</td><td>64</td><td>20</td><td>22.14</td><td>20</td><td>16.32</td></tr>
<tr><td>Hydro D</td><td>14</td><td>30</td><td>33.21</td><td>30</td><td>24.47</td></tr>
<tr><td>Total =</td><td>155</td><td>140</td><td>-</td><td>155.00</td><td>190</td><td>-</td><td>155.00</td></tr>
</table>

Scenario 1 in Table 3.7 corresponds to the same example shown in Table 3.5 (Section 3.2.4). In scenario 2 it is supposed that Hydro A, instead of seasonalizing 50,000 MWh, allocates 100,000 MWh for that period. The total verified energy (equation 3.7) to be allocated for each hydro is given by multiplying its own production by the adjustment factor. This factor, also know by Generating Scaling Factor (GSF), is then computed by the ratio between the total production and total seasonalized physical guarantee of the hydros into the *MRE* for this period (equation 3.6). If the GSF is less than 1, the hydros are generating less than their physical guarantee.

$$\mathbf{GSF} = (MRE\ total\ production) \div (MRE\ total\ physical\ guarantee) \tag{3.6}$$

$$\mathbf{Verifed\ energy} = \mathbf{GSF} \times (Own\ production) \tag{3.7}$$

[41] Itaipú is a binational hydro power plant shared between Brazil and Paraguay which has an installed capacity equal to 14 GW (i.e. the second largest hydro in the world).

[42] It is included into the *PROINFA* (Program of Incentives for Alternative Electricity Sources) 59 small-medium sized hydros (equivalent to the category classified in Brazil as "*PCH*", presented in section 3.1.2). All these power plants totaling 1.15 GW of installed capacity [Eletrobras, 2014c].

In sequence, the Financial Settlement (FS) that takes place into the *MCP* was computed according to equation 3.8.

$$\mathbf{FS} = (Own\ production - Verified\ energy)\times TEO +$$
$$+ (Verified\ energy - Contracted\ energy)\times PLD \quad (3.8)$$

As it can be realized, if Hydro A adopts the strategy of increasing the seasonalized physical guarantee from 50,000 to 100,000 MWh, keeping everything else constant, after processing the *MRE* 81,580 MWh will be allocated to Hydro A instead of 55,360 MWh, while for all others hydros the amount of the verified energy will decrease. If in this period Hydro A has more verified energy than contracted energy (situation characterized in Figure 3.17), this difference will be sold in the *MCP* at the *PLD* price. If the *PLD* is high, the profit can be remarkable. However, this strategy affects (decrease) the verified energy that will be allocated to others hydros participating in the *MRE*, which can originate negative exposed positions (as represented in Figure 3.16). Until a certain point, this situation is part of the game and generators have to deal with this risk. Though, it can be unfair if some hydros can perform the seasonalization and others have this action restrained.

Due to this loss, Eletrobras appealed to ANEEL in order to suspend the *MCP* settlement and to cancel the seasonalization related to January and February. The whole process caused a temporary shutdown of the short-term market (encompassing around R$ 6 billion or U$ 2.5 billion), and created an insecure climate in the electricity sector. In March 2013, the ANEEL's Board of Directors decided not to change the seasonalization of these months [ANEEL, 2014a]. In addition, in order to change the *MRE*'s rules from this point forward, it was opened a public hearing process that lead to the publication of the ANEEL Normative Resolution 584/2013.

During the discussion of this issue with market participants, ANEEL's technical superintendents performed an analysis based on actual monthly data regarding the electricity production and the seasonalized physical guarantee of all *MRE*'s participants (528 power plants) [ANEEL Technical Note 054/2013-SRG-SEM/ANEEL]. This data was provided by CCEE and covered the period from September 2000 until December 2012. The purpose was to assess alternatives in order to "protect" hydros that cannot accomplish the seasonalization from the effect of the seasonalization of physical guarantee performed by agents who could use this mechanism.

Two scenarios were employed in this analysis: one with seasonalizations indeed performed by agents, also called "occurred" seasonalizations; and other to simulate an "extreme" seasonalization, i.e., for those agents that can do it, the seasonalization of approximately 60% of the physical guarantee was shaped following the profile of the average *PLD*. In the extreme seasonalization scenario with the MRE's rules as usual it is possible to observe that, when hydros perform the extreme seasonalization, they benefit from the fact that other agents cannot implement seasonalization. In this case, a transfer of large financial amounts clearly occurs in the *MCP.* Notwithstanding, in the extreme seasonalization scenario with the new MRE's rules, if a protection (or a "shield") scheme was implemented for hydro stations that are unable to seasonalize their physical guarantee, this phenomenon did not occur.

In the end, the solution adopted is detailed in the ANEEL Normative Resolution 584/2013, which establishes the terms and the conditions for seasonalization of the physical guarantee. This norm gives the possibility to separately seasonalize the physical guarantee for physical coverage contracts purposes from the physical guarantee for *MRE* energy allocation purposes[43]. Regarding the *MRE* purposes, for the hydro stations that are allowed to perform the seasonalization of their physical guarantee, it was preserved the flexibility to define their monthly allocation, while for those that do not have such flexibility or want to adopt a more conservative strategy, the seasonalization of the physical guarantee is automatically performed following the seasonalization profile of the other agents participating in the *MRE*.

On balance, for those hydros that can perform the seasonalization process of the physical guarantee, there is still a single "window" to set the (monthly) amount of physical guarantee that will influence the verified energy, which is employed to confront the amount of the contracted energy. Furthermore, the "shield" currently implemented in the *MRE* for some hydros does not eliminate the hydrological risk of all *MRE*'s hydros becoming negatively exposed in *MCP*. This issue brings us to the second situation that recently occurred in the Brazilian electricity market and it also highlights some weakness associated to the seasonalization and the *MRE* processes.

*3.3.3.2 Hydrologic crises and the MRE's performance in long run*

The second situation can occur whenever some events happen simultaneously. Every time the *PLD* is high, there are more thermal stations that are dispatched and less hydro dispatched ones. Thermal power plants are typically contracted in the "availability type auctions" (as described in Section 3.2.1), and thus they receive an availability payment and an additional remuneration for each MWh effective produced. Nevertheless, hydro power plants are normally contracted in the "quantity type auctions" (as defined in Section 3.2.1), so they are committed to deliver a certain amount of electricity (MWh) at a pre-defined price. The difference between the contracted energy and the verified energy must be automatically bought or sold in the *MCP* at the *PLD*.

So, depending on the amount of thermal dispatch, hydros in all submarkets can be displaced in such a way that, in the end of the day, the total production in the *MRE* will not be higher or equal than the total physical guarantee of the *MRE*'s hydros. As a result, *MRE* will not have the extra energy to be shared among its participants, and then the GSF (equation 3.6) is less than 1. In other words, the adjustment factor (GSF) will be applied to withdraw a fraction from the seasonalized physical guarantee. As the seasonalized physical guarantee is monthly allocated to cover the monthly amount of the contracted energy, a large decrease in the seasonalized

[43] The seasonalization of the physical guarantee for physical coverage contracts (PG_COVERAGE) and the seasonalization of the physical guarantee for MRE energy allocation (PG_MRE) have different goals and applications. The first one was implemented to check (and apply penalty) if there is any amount of contract not supported by a physical guarantee (the currently Brazilian market was planned to push the equilibrium between contracts and physical guarantees), and this is done by calculating the difference between "resources" (physical guarantee and purchase contracts) and "requirements" (sales contracts) for each agent considering 12 months previous to the month of calculation. The second one was designed to deal with the risk associated with the centralized dispatch of the ONS.

physical guarantee of all hydros into the *MRE* (there are 528 power plants) originates a widespread negative exposed position for these hydros.

This situation is illustrated in Table 3.8 and in Figure 3.21. Since the total generation (80,000 MWh) is less than the total physical guarantee (140,000 MWh), the adjustment factor (0.571) will be lower than one, and the verified energy will not fill the level of the physical guarantee. Considering the *TEO* value established for 2014 (10.54 R$/MWh) [ANEEL Approving Resolution 1658/2013] and a *PLD* value consistent with a situation of energy shortage (700 R$/MWh), the total financial settlement (equation 3.8) of this operation is equal to a loss of R$ 42 million.

**Table 3.8 – Into *MRE*: when things go really bad**

| Hydro | Own production (MWh x 1,000) | Physical guarantee (MWh x 1,000) | GSF | Verified energy (MWh x 1,000) | TEO (R$/MWh) | PLD (R$/MWh) | Contracted energy (MWh x 1,000) | Financial Settlement (R$) |
|---|---|---|---|---|---|---|---|---|
| Hydro A | 37 | 50 | 0.571 | 28.57 | 10.54 | 700.00 | 50 | -14,911,163 |
| Hydro B | 12 | 40 | | 22.86 | | | 40 | -12,114,434 |
| Hydro C | 7 | 20 | | 11.43 | | | 20 | -6,046,677 |
| Hydro D | 24 | 30 | | 17.14 | | | 30 | -8,927,726 |
| **Total =** | **80** | **140** | **-** | **80.00** | **-** | **-** | **140** | **-42,000,000** |

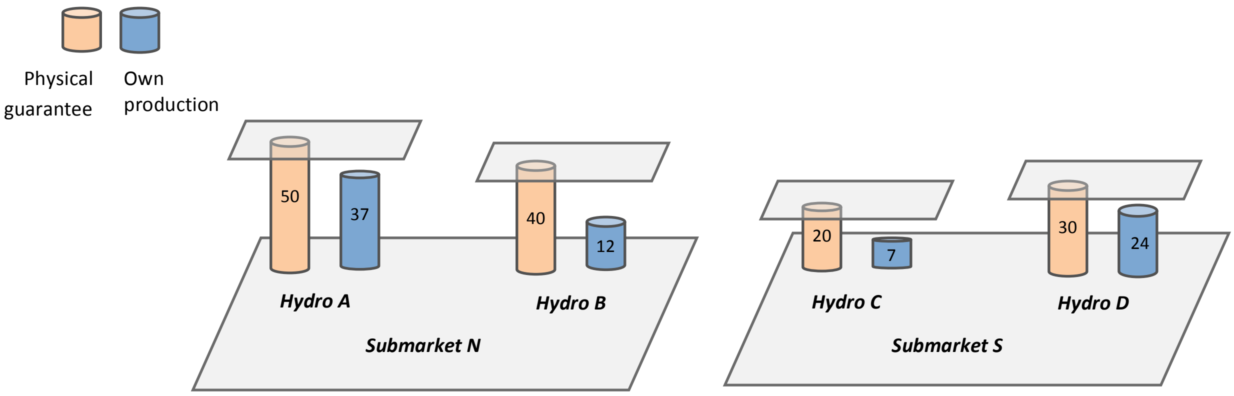


**Figure 3.21 – The operation of the MRE: if total generation is less than total physical guarantee**

Now, considering that this situation can last for some months and that several hydros must buy energy in the *MCP* at a very high *PLD*, this can affect their cash flow. So, as can be noted, when a significant amount of expensive thermal generation has being called to supply the load for a longer time, more hydros around the country are turned off. During this entire period the adjustment factor will be lower than one, so that there will be a widespread significant negative exposure supported by hydros.

In short, in situations like these the *MRE* is not able to cover the risk of generators that have to buy electricity in the short-term market to complete the energy committed in their contracts. This risk is called “hydrological risk”, and it is due to the fact that hydros are being dispatched at low levels because there is not enough water in their reservoirs and the power system is facing a severe period of water shortage.

Since the first reform of the electricity sector in 1998, the Brazilian power system faced three periods of electricity price spikes: from 2001 until the beginning of 2002; in the beginning of 2008; and from 2012 to 2014 (see Figure 3.19). Recently, the situation discussed above (large thermal dispatch, widespread water shortage across the country, hydros with their physical guarantee extensively committed though contracts, and sky-rocketing short-term prices) is even more evident because it lasted for a longer period. Because of that, in 2014 hydros appealed to the Federal Government for a financial support:

> "Hydro generators prepared a request for help to the Federal Government in order to equalize the negative financial impact on revenue of hydro power plants participating in the Mechanism for Reallocation of Energy (MRE). Consultants estimate that the exposure of the generators of the short-term price can cause a loss of over R$ 20 billion in 2014." [Jornal da Energia, 2014]

The Federal Government has been arguing that this is a business risk of hydros. Hydros argue that the continuously growing price curve was not taken into account by generators when they signed the long-term contracts, and that the dispatch out of merit order carried out by the CMSE (explained in the end of Section 3.3.2) causes market distortions. At the end, this arm wrestling may indicate either a cyclical or even structural imbalance in the current market design. Within this conjuncture the question to be answered is as follows: Is there a way to improve the conciliation between the physical operation and the ex-ante contracts?

If each hydro decides its own production, their reservoirs would be managed on their own. In the Brazilian case, the power system dispatch is done in a centralized way so that the entity that decides the production levels is a third party that doesn´t assume this "hydrological risk". This risk is assumed by the hydros[44] and, as stated in the previously, the *MRE* doesn´t cover it. Nonetheless, as point out by [IEA, 2005], the framework of incentives should be structured such that risks are allocated to the entities that take the decisions and that hold the responsibility for taking them into account.

Again, it seems that it is missing in this market design some flexibility to enable hydros to adequately manage this risk. Generators agree to sell electricity at a certain price for a long period (30 years), and during this period water shortages can occur that force them to buy a large amount of electricity at a fairly high price corresponding to the variable cost of the last dispatched thermal power plant. However, they cannot manage their reservoirs to save water according to their own risk perception.

## 3.4 Final remarks

This chapter details the main features of Brazilian electricity market. Then, focusing on a hydrothermal power system with a large share of hydros, three concerns regarding this market were discussed: the efficiency in the use of the energy resources; the security of supply and the capacity mechanism; and the need to enhance the flexibility for generators to endure with

[44] However, for those hydros that accepted the renewal of the concession according to the Law 12783/20013 and Decree 7805/2012, the hydrological risk is supported by the consumers [ANEEL Technical Note 054/2013-SRG-SEM/ANEEL].

their closed contracts. At the end, both the market adequacy in the long-term and the market completeness in the short-term were examined. To summarize the main points regarding this electricity market, in particular focusing on the *ACR*, the next paragraphs describe its temporal and logical sequence:

i) in the beginning of each year, the MME (Ministry of Mines and Energy) receives from the Discos their data regarding the forecasted demand for the next five years. Discos in the *ACR*, and free consumers in the *ACL*, need to contract 100% of their expected demand, otherwise penalties will be imposed to them;

ii) the EPE (the state-owned company created to support the MME in the energy planning) studies energy resources potential that are needed to meet the future demand;

iii) considering the information about both demand and supply and based on the energy planning for the country, the MME sets what types of national public auctions will be implemented to contract energy to the captive consumers;

iv) these public auctions are designed so that affordable tariffs can be achieved;

v) ANEEL (the electricity regulator), or CCEE (the market operator) if delegated by ANEEL, run the national public auctions in order to buy the electricity needed to supply the captive consumers;

vi) generators that were successful in these auctions sign PPAs with Discos that demanded electricity for the MME as a condition to receive the concession grant to build and explore the generation activity;

vii) in the end of each year, all contracts and physical guarantees must go though the seasonalization process;

viii) in each week a software package is run in order to centrally dispatch the system. This is done by the ONS (the system operator), that determines the dispatch of the generators without considering their contracted energy. The short-term price (*PLD)* comes also as a result of these simulations;

ix) generators follow the dispatch mentioned in step viii), and real productions are measured by CCEE;

x) The *MRE* is run to share among the hydro participants the risk of not being dispatched;

xi) CCEE has in its records all the seasonalized contracts and physical guarantees. Together with the amounts actually produced/consumed by each agent, CCEE accounts for the differences between the contracted energy and the verified energy;

xii) The remaining differences are valued using the short term marginal price (*PLD*).

These events are also synthesized in Figure 3.22.

The market adequacy is provided by a mix of capacity mechanisms (for both contracting environments, the *ACL* and the *ACR*), and the expansion of the system is planned in a centralized way by the MME and the EPE. In Brazil, once a year there is a “window” to monthly distribute quantities of the physical guarantee and the contracted energy. There is not a short-term market to allow adjustments of positions (the *MCP* just settles imbalances), and the *MRE* doesn´t cover the hydrological risk if all *MRE*'s members become negatively exposed in the *MCP*.

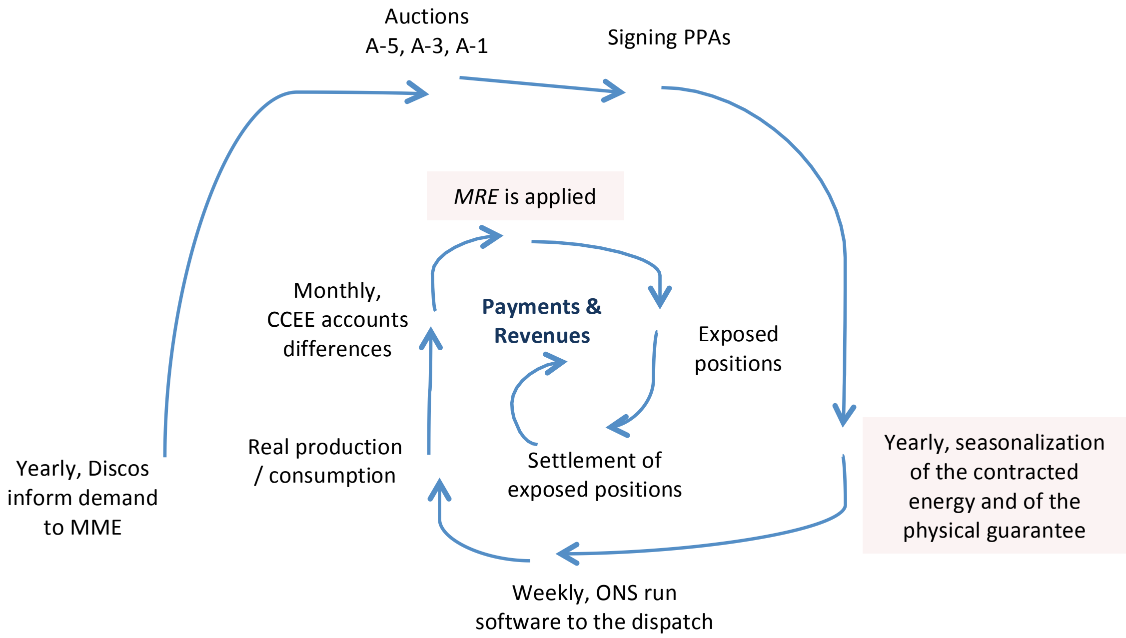


**Figure 3.22 – Synthesizing the main points of the *ACR***

The problems that arise are, thus, related to the following issue:

- in the medium and in the short-term, generators are not allowed to define the amount of energy to comply with their contracts;
- the *MCP* is a mechanism to settle differences true than a market. Participating agents do not make any short-term declaration of intention, and the *PLD* is not the result from the interaction between market participants. Instead, the *PLD* comes from the application of a chain of software; and
- the codes of this chain of software (NEWAVE and DECOMP) are under intellectual property rights. However, inconsistencies in these algorithms have a huge impact within the entire sector so that the confidence in the market can be affected.

As suggested in Chapter 2, a solution typically adopted in other markets is the employment of a more market-oriented approach. Such approach could enable all generators to offer quantity and price bids in the short-term, which would be used to set their market positions and, consequently, substitute the seasonalization and the MRE. As a result, the short-term price would be based on the interaction between market participants. Nevertheless, through the analysis in this chapter, it became clear how important it is to coordinate the use of the water stored in the reservoir in order to safeguard the efficiency of using the energy resources, and how relevant is to have enough incentives to ensure the security of supply of the country.

The next chapter presents the solution developed in the thesis to overcome this dilemma. The proposed model aims to ensure the mentioned efficiency and security, while focuses to improve the flexibility to enable market participants to withstand their contracts.

# Chapter 4 – Virtual Reservoir Model and its algorithm

This chapter discusses models designed to expand the employment of liberalized approaches into power systems with large share of hydros (Section 4.1), and presents in detail the model that was developed in the scope of this thesis (Section 4.2). This model is based on the concept of energy right accounts as virtual reservoirs and, considering some elements of a centralized and decentralized market-based economy, it aims at increasing the degree of flexibility to enable generators to uphold their contracts while ensuring the efficient use of the energy resources and together with the security supply of the country.

Then, Section 4.3 addresses the modeling alternatives to understand the generators' behavior, and Section 4.4 details the Agent-Based Model (ABM) with a Q-learning mechanism. Finally, Section 4.5 is dedicated to the description of the algorithm developed for the simulation of the behavior of market participants in this new market design.

## 4.1 Market designs for power systems with a large share of hydros

In general, the literature that addresses the analysis of liberalized wholesale electricity markets deals with power systems that operate with a large share of thermal power plants. When one is facing a power system with a high share of hydropower plants the decision making of the market participants becomes more complex mainly because of the following issues:

- Temporal coupling: It means that the present decisions will affect future decisions since the use of the water from the hydro reservoirs depends on the availability of affluent natural energy inflows (i.e. it depends on the amount of rain that will fall into the watershed and that will flow through the river where the hydro is located) [45]; and
- Space coupling: Within the same cascade, the decision for electrical energy generation (i.e. to release the water stored into the reservoir, through the turbines) by the upstream hydropower plant affects the decision of the downstream hydropower plants because it influences the short run availability of the water and the productivity of the power plant, since the variation of the reservoir's water level changes the potential energy storage in the reservoir.

Regarding the first type of coupling mentioned above, for thermal power plants it is assumed that the fuel is always available to be used whenever needed, or at least the availability of the fuel is previously known by the decision maker. Unlike thermal, it is more demanding for hydropower plants to have such knowledge especially because hydros have no direct costs, but opportunity costs, and the optimal bidding strategy involves the trade-off between the maximization of its immediate revenue by selling energy in the market and the maximization

[45] Thermal power plants can have temporal coupling if considering their ramps, and this is due the operation of the turbine. This type of temporal coupling is not present in hydros since for them it is a question of changing the position of a valve and they respond in a few seconds. The temporal coupling of hydros treated here come from the fact that the resource is finite and if a lot of water is used now them less water is available in the future.

of future revenues by storing this energy for later usage. Thus, the hydropower plants should make their bids based on the water value of its reservoir. This complexity can be addressed forecasting the affluent natural energy inflows and using stochastic dynamic programming. Section 3.2.3 showed that in Brazil this issue is addressed by a centralized dispatch carried out by the ISO. However, in a decentralized dispatch scheme, each hydropower plant can perform the analysis regarding the future water availability. When doing so, each hydro would be responsible for the forecast of the water that will fall and flow until reaching its reservoir.

Nevertheless, the space coupling, which doesn't exist for thermal power plants, is problematic in markets where different companies own hydros in the same cascade. As observed in Sections 3.2.3 and 3.3.1, when a cascade has several power plants operated by different owners the decentralized dispatch cannot lead to the global optimal solution regarding the efficient use of the resources. In other words, the sum of the total individual revenues obtained by each company may not coincide with the optimal global revenue associated with the use of the available energy resources in the cascade if determined in a more integrated way. Just to illustrate some hydro's cascade in Brazil, Figure 4.1 shows the main hydros inside of some watersheds of the Southeast submarket. For each station, the first name corresponds to the name of the station and the second one to the company's name.

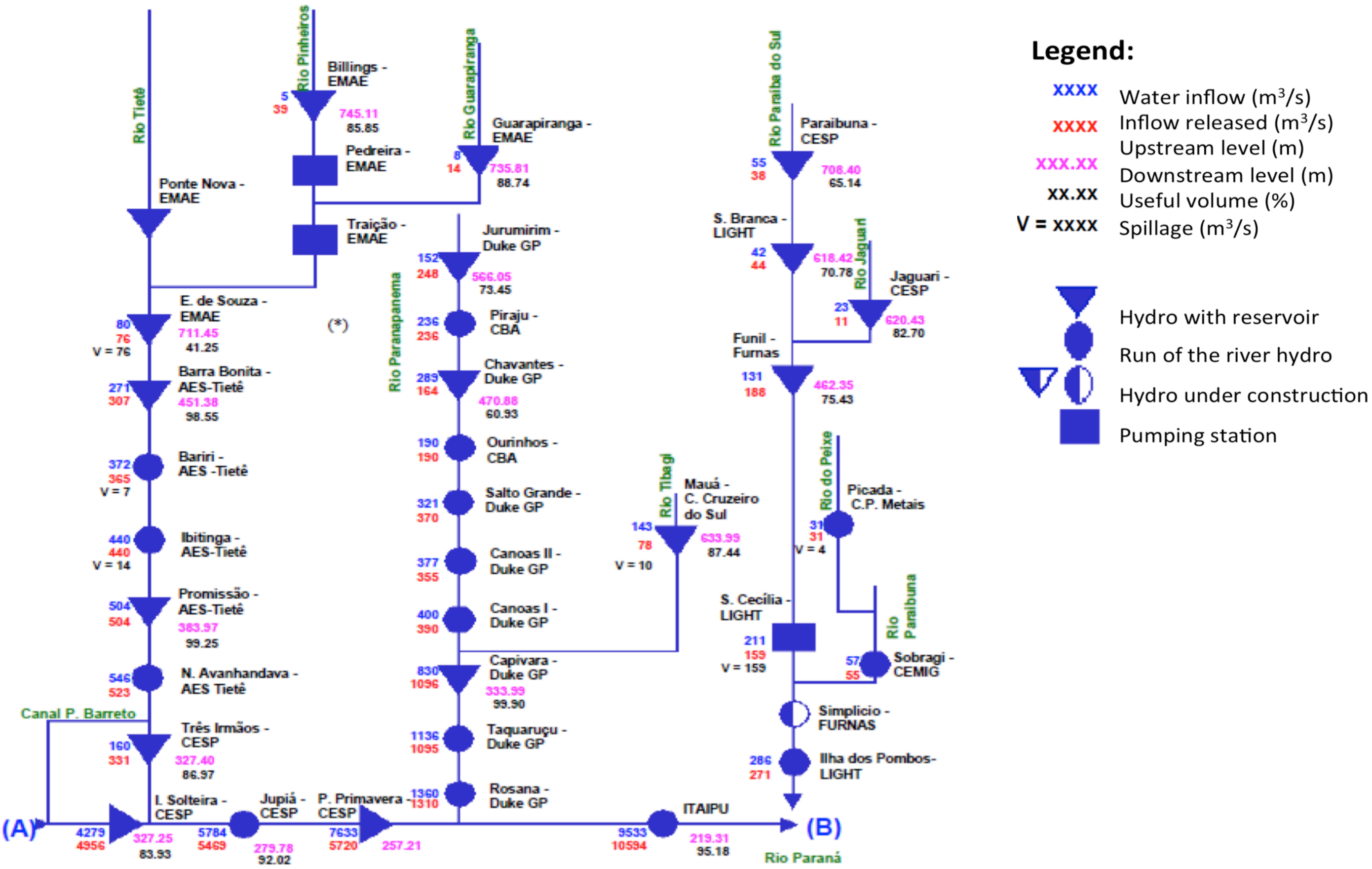


**Figure 4.1 – Cascade of dams in Tietê, Paraná and South Paraibuna watershed [ONS, 2013]**

Considering that (i) the Brazilian power system historic operates with around 80% of hydropower generation, (ii) different private and public companies coexist in the same cascade, (iii) the dispatch is centralized by the ISO, and (iv) the short-term prices are formed by a minimum cost dispatch approach, the design of a suitable market structure is a complex issue, and just few studies have raised substantial alternative approaches to address a liberalized and decentralized Brazilian electricity short-term market.

For hydrothermal power systems, [Kelman, 1999] shows that the downstream hydro power plants capture part of the revenues that should be attributed to upstream hydros. This author illustrates this concern through the problem of the coexistence, in a same cascade, of an upstream “pure” reservoir (only the dam) to a downstream run of the river hydro. The upstream pure reservoir must be remunerated for its investment since it brings the benefit of the stream inflow regulation for the downstream hydros, which allows increasing the electricity production of the downstream units in the dry season.

However, the usual scheme of the wholesale electricity market only pays the generated electricity. Then, [Kelman, 1999] proposes the creation of a Wholesale Water Market (WWM) to adjust it. From this point of view, a reservoir is an economic agent "buying" water during raining periods and storing it until the arrival of the dry season. The turbine/generator is an economic agent “purchasing” water to produce electricity to be sold in the market.

The Revitalization Committee of the Power Sector, created by the Brazilian government in 2001[46] in response to the energy crises that Brazil faced in 2001 and 2002 due to a long and tough drought, suggests the implementation of a series of measures, among which are [Revitalization Committee of the Power Sector, 2002b]: assurance of the supply expansion, monitoring of the supply reliability, strengthening of the market, prevention of the exercise of market power, and enhancing the effectiveness and transparency of operation of the institutions.

Concerning the strengthening of the market, it was advocated the implementation of a dispatch process and market based on bids. The Committee stated that the determination of the production of each plant and the short-term price by computational models (as is done nowadays) is not ideal for assigning individual responsibilities to the owners of the hydros to fulfill their contracts. This is because the calculation of prices that existed at that time (and it still exists) does not allow companies to price their energy portion of power system. In addition, companies could understand that they are not responsible for complying with their contracts if the stored energy in their reservoirs was decreased due to ISO’s decision [Revitalization Committee of the Power Sector, 2002a].

[46] The Resolution GCE (Board of Management of Electricity Crisis) nº 18, published on June 22, 2001, created the Revitalization Committee of the Power Sector with a mission to present proposals to correct the dysfunctions and propose improvements of market design.

Besides that, another issue regarding the Brazilian centralized dispatch is related to the non-diversification of the system operation risks. The ISO collects and manages a large amount of information about each agent as well as other parameters of equal importance (such as hydrologic and demand scenarios), and the criteria for selecting the information, modeling of future uncertainties and decision making are necessarily unified. On other hand, a scheme based on offers of price/quantity bids incorporates the diversity of agents' perceptions with respect to future uncertainties of supply, demand, fuel prices as well the water inflow conditions [Revitalization Committee of the Power Sector, 2002b].

In the end, this Revitalization Committee proposed a market design with the following characteristics [Revitalization Committee of the Power Sector, 2002a & 2002b & 2002c]:

- Creation of an Energy Rights Account (ERA) for each hydro;
- For each accounting period, the ERA is fed by the fraction of the total Natural Affluent Energy (NAE) of the submarket proportional to the physical guarantee of the respective hydro;
- Each hydro offers quantity/price bids in a short-term market, and the amount offered is limited to the ERA balance;
- All agents (hydros and non hydros) participate in this short-term market;
- Considering the market clearing price, the total amount of energy coming from hydros and other sources of energy is determined;
- Based on the total amount of energy sold by hydros, the ISO is responsible for making the optimal physical dispatch of the hydros into each cascade. Thus, it is not necessary that the physical generation of each individual hydro corresponds to energy offered and sold by the hydropower;
- The connection between the physical and the commercial operation is related with the following requirement: the total physical production of hydropower plants must be equal to the sum of hydros agents' accepted offers.

In short, first the market clearing is achieved and the dispatch order of all power plants is obtained. Then, considering the total amount of hydro dispatch, and in order to optimize the hydro cascades, the ISO refines the amount of generation of each hydro in a more precise way.

## 4.2 The Virtual Reservoir Model (VRM)

### 4.2.1 Operation of the VRM

Focused on improving the flexibility to enable market participants to comply with their contracts, while still ensuring the efficient use of the energy resources and maintaining the current security of supply level, and partially considering the proposal of the Revitalization Committee of the Electricity Sector (2002), a new market design was developed to be applied to the Brazilian power system. Based on the concept of energy right accounts as virtual reservoirs, in this new model, named Virtual Reservoir Model (VRM), each hydro is modeled as an agent that has a virtual reservoir representing how much energy is virtually stored in his hydro plant. Hereafter, for each accounting period, each account is fed by the fraction of the total Natural Affluent Energy (NAE) that flowed to the hydro cascade proportionally to the hydro's physical guarantee. Then, the following sequence of events is adopted:

1º The system operator continues his work as it is currently done (running NEWAVE, DECOMP as well as other software, procedures and schemes), and defines the amount of generation for each power plant. This means that it maintains its responsibility in terms of defining the physical dispatch in order to optimize the use of the resources and dispatching the hydro and thermal units;

2º The "remaining demand" is obtained for each dispatch period. This remaining demand is equal to the total demand minus the total dispatch allocated to the thermal power plants. This difference is the total demand to be supplied by hydros;

3º A hydro short-term market based on bids is established for the remaining demand. In this market, hydros have the opportunity to withstand their bilateral contracts whereas they are trying to have successful bids. The result of this market is a virtual dispatch with financial settlement purposes. To do that, hydro agents can offer bids considering a price between zero and a ceiling price (e.g. the cost of the cheaper thermal power plant dispatched in this period) and the limit quantity corresponds to the energy available in his account;

4º The final short-term price is calculated as a weighted average considering the most expensive successful hydro price bid and the variable cost of the last non-hydro resource dispatched by the ISO.

Unlike the proposal of the Revitalization Committee, in this case the ISO defines in the first place the amount of generation of each power plant, through the computational models package and with the goal of optimizing the power system and addressing the security of supply. Then, considering the "remaining demand", hydros participate in a short-term market aiming to be successful through their offers in order to endure their contracts.

Through VRM, the ISO will freely operate the physical system and hydro agents would be responsible for deciding, in commercial terms, how much they want to withdraw from their virtual reservoirs to meet their contracts. To do that, their bids have to be accepted in an auction that will be performed as a day-ahead market. In doing so, each generator has the opportunity to manage its contracts more efficiently, without affecting the real operation of the physical system.

As can be observed in Figure 4.2, in the VRM two worlds would coexist: the real one, associated with the power system considering physical effects, and where the ISO runs the dispatch in a centralized way; and the virtual one, related to the settlement system and with commercial effects, and where hydro agents participate in a short-term market. Both worlds simultaneously operate, and the link between them is the total affluent natural energy that flowed along the hydro cascade in each accounting period. At last, the settlement process will occur considering the successful quantity bid of each participant, and the exposed position will be valued by the new final short-term price.

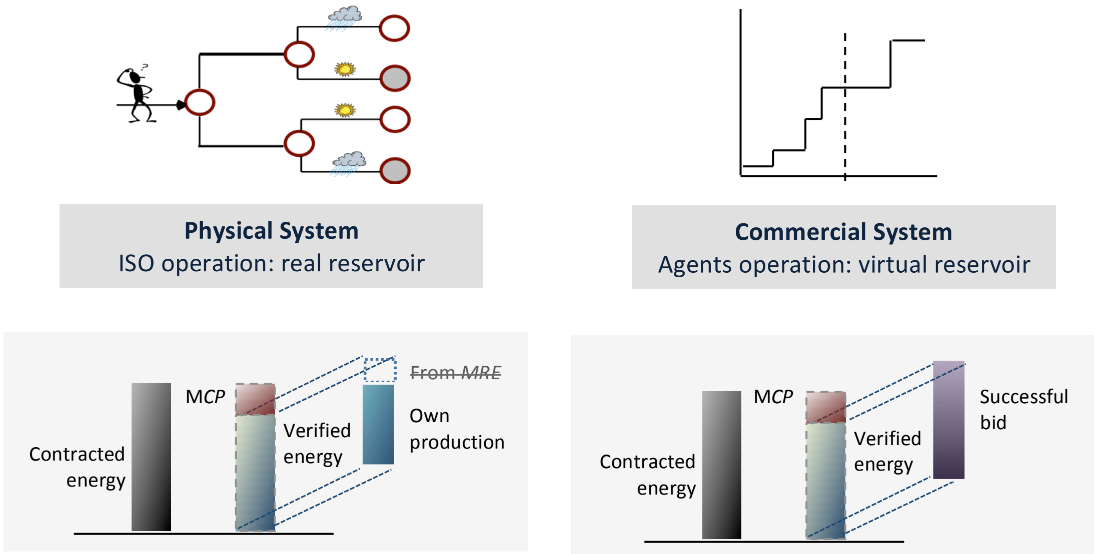


**Figure 4.2 – Physical System (ISO operation) versus Commercial System (agents operation)**

By doing so, the *MRE* and the seasonalization process of the physical guarantee (two mechanisms of the current Brazilian market) will be replaced by the virtual hydro short-term market. Thus, the settlement process will occur considering, for each hydro, the "successful quantity bid" (equation 4.1) instead of the "own production defined by the ISO" plus the "allocated energy from the *MRE*" (equation 3.2). Thus, the "verified energy" is now given by:

$$\textbf{Verified energy} \; = (successful\ quantity\ bids) \tag{4.1}$$

Nevertheless, the "contracted energy" and the "exposed position" remain unchanged (equation 4.2 is equal to equation 3.4, and equation 4.3 is equal to equation 3.5):

$$\textbf{Contracted energy} = (closed\ contracts\ afthe\ the\ seasonalization\ and\ modulation) \tag{4.2}$$

$$\textbf{Exposed position} \; = (verified\ energy) - \; (contracted\ energy) \tag{4.3}$$

At the end of this process, the prices no longer result primarily from a chain of computational models that may eventually present problems related with inconsistencies and transparency, but they are obtained through the combination of thermal costs originated from the ISO dispatch and the short-term market price arising from the liberalized hydro short-term market. A mix of centralized dispatch and market based on bids can, therefore, increase the confidence of market participants and improve the transparency and regulatory stability of the power sector.

Furthermore, with both the physical and virtual dispatches operating in parallel, it can be possible to analyze the ISO performance based on comparisons of decisions, namely the ISO's decisions (physical world) versus agents' decisions (virtual world). To address this issue, Figures 4.3 and 4.4 present schematic drawings illustrating the decision making process in this new market design.

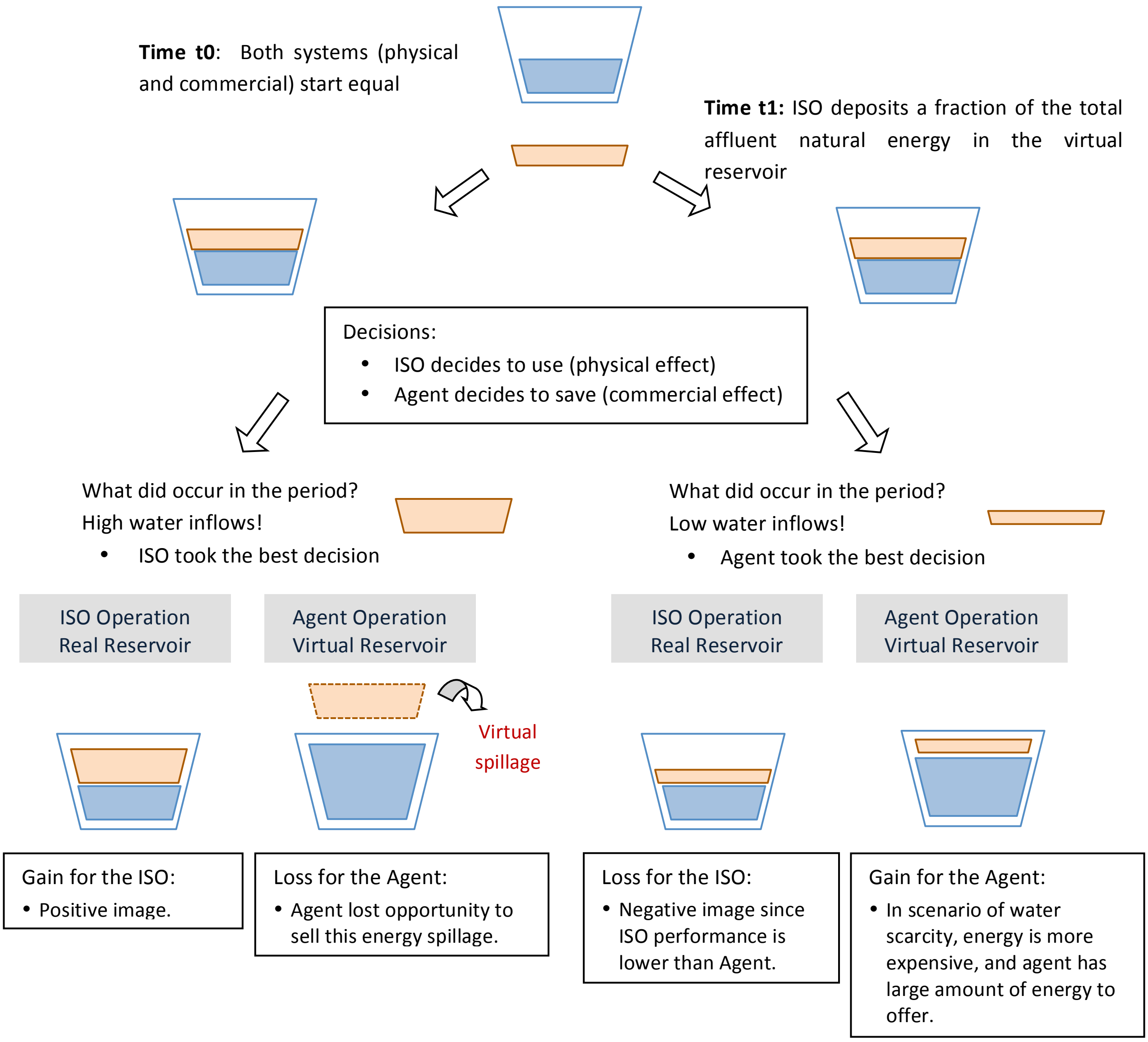


**Figure 4.3 – Decision making process: ISO decides to use water; agents decide to save water**

In Figure 4.3 the ISO decided to use water, while the generation agent decided to save it. As can be observed, if the ISO took the best decision he will have a positive image and the agent will lose the opportunity to offer the spilled energy. On the other hand, if the ISO took a wrong decision and the agent a right decision, the ISO will have a negative image and the agent will have the opportunity to sell the energy that he saved when there is a water scarcity and, thus, the energy price is higher.

When these decisions are reversed (ISO decided to save and the agent to use), instead of having a virtual spillage, it can happen a physical spillage, as shown in Figure 4.4. However, the same reasoning regarding gains and losses is applied.

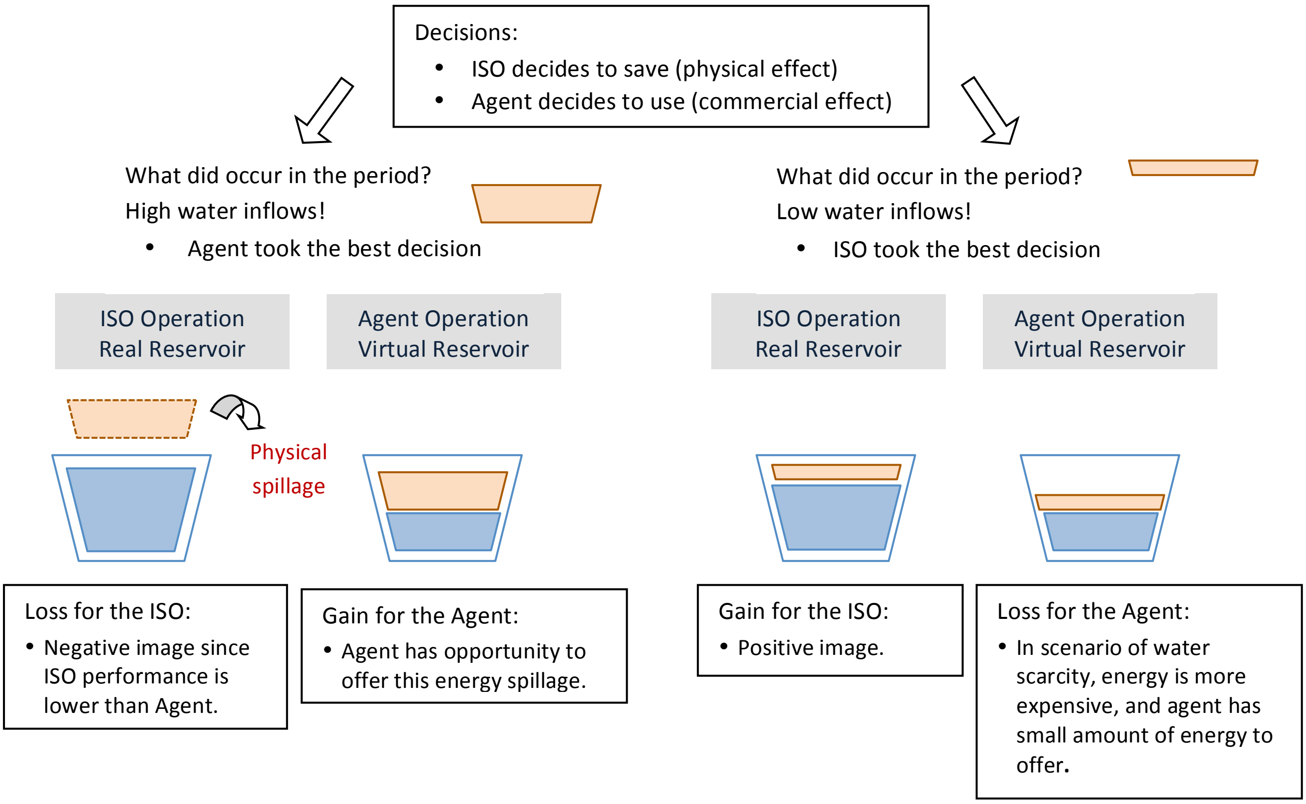


**Figure 4.4 – Decision making process: ISO decides to save water; agents decide to use water**

Finally, this market design maintains the same levels of the previously mentioned efficiency and security, while it increases the level of flexibility of the agents' commercial aspects. This flexibility can be achieved by replacing the *MRE* and the seasonalization of the physical guarantee by the proposed Virtual Reservoir Model. As a consequence, the management of (virtual) reservoirs is under the responsibility of each hydro, which could (virtually) save water according to their own risk perception. On the other hand, the operation of the physical system is not affected, ensuring the efficiency of the hydro cascade and maintaining the current security of supply level.

### 4.2.2 Additional issues

Going deeper in this new market design, some issues are detailed in the next sections.

#### *4.2.2.1 Trading period*

Short-term markets usually operate with bids for the delivery of energy in next day. Considering a further reform of the Brazilian electricity market, a week-ahead market seems to initially be a better option due the current weekly dispatch. In this case, the virtual reservoir model will operate as following: (i) the *ERA* should be fed once a week considering the energy inflow that flowed in the cascade during that week, (ii) the short-term price should be weekly set, and (iii) transactions between sellers and buyers should also be settled on weekly basis.

However, if it is intended to operate the hydro short-term market as a day-ahead market, every day the ISO must measure the amount of the energy inflow that flowed within the cascade during the previous day and to deposit the corresponding amount in each hydro *ERA*. Then, day-to-day the ISO dispatches the system and computes the remaining demand. Subsequently, hydros daily communicate bids including 24 pairs of quantity and price (each pair for one hour of the next day) in order to withstand their contracts and set the clearing price. Finally, the settlement process, which considers the contracted energy and the accepted quantity bids, must be performed in the same basis.

As it can be noted, the complexity of the day-ahead market is higher than the week-ahead market, but the short-term prices obtained from the daily market will represent the system conditions more accurately. Moreover, it can further improve the competitiveness and completeness of the market, and facilitate the materialization of reference prices that send more relevant price signals to the participants. So, the day-ahead market of the virtual reservoir model could be timely implemented as a second stage of the reform.

#### *4.2.2.2 Amount deposited in the ERA*

It was stated that the amount that must be deposited in each ERA by the ISO should be the fraction of the total Natural Affluent Energy (NAE)[47] that flowed within the cascade proportional to the hydro's physical guarantee. This calculation is shown in equation 4.4 ("i" represents the hydro index and "t" is the trading period index).

$$DEP_{it} = \frac{NAE_t \times PG_i}{\sum_{i=1}^{n} PG_i} \tag{4.4}$$

This designation was chosen because, considering the cascade operating as a unique reservoir shared by several owners, this value gives to each owner a fair fraction of the inflow. It is also important to emphasize that, according to the aforementioned definition, the downstream hydros are not influenced by the decision of the upstream hydros. If, for instance, the amount deposited in the *ERA* is the exactly amount of water that reaches the hydro's reservoir (i.e. the affluent energy of the hydro), this deposit would be influenced by the quantity of water released by the upstream hydros and, thus, by the centralized dispatch of the Brazilian ISO. Besides, this deposited value connects the hydros' decisions with the actual conditions of the

[47] The total Natural Affluent Energy (NAE) of a cascade of hydros is the energy that is obtained when the Natural Affluent Flow (NAF) of the river and his tributaries passes through the turbines of all hydros located in this cascade. Thus, to convert the NAF in the NAE it is considered the productivity of the hydros.

watershed where the hydros are located, which represents a feasible link between the virtual world and the real world.

#### *4.2.2.3 Amounts withdrawn from the ERA*

Regarding the amounts that should be withdrawn from the *ERA*, besides the quantity bid that corresponds to a hydro's decision, it is also pertinent to consider other subtractions. Aiming at creating a hydro short-term market more adherent to the real world, the following variables can be considered into the scheme:

- Virtual spillage: In parallel to the physical spillage, a virtual spillage can occur within the virtual reservoir model. Both spillages are related to the physical capacity of the reservoir. However, while physical spillage is related to the current real level of the reservoir, the virtual one is connected with the level of ERA. The consideration of virtual spillages into the rules of this market design can contribute to curb speculation in (virtual) water management since there will be no reservoirs with infinite storage capacity. For instance, hydros can save water in order to offer energy when the resources are scarce and thus prices go up. Nevertheless, even hydros that are not committed with bilateral contracts (and therefore are totally flexible to manage their virtual reservoir just considering the short-term market) can save water and until a certain point, which is exactly the reservoir's level that starts originating the spillages.
- Minimum outflow of the hydro: Some hydros have to constantly maintain a minimum outflow from the reservoir since they can have restrictions in the downstream of the river regarding the need for water (e.g. to keep the aquatic fauna and flora of the river, as well as to support human activities such as irrigation, transportation, recreation and fishing). Thus, this physical minimum outflow of the dam can be represented in the virtual reservoir model as a virtual withdrawal. Technically speaking, this concern can be modeled as a bid in which the price is equal to zero, and the bid quantity is equal to the required minimum outflow.
- Losses of the power system: Sharing rules of physical losses of the power system, notably regarding electrical losses in the transmission and distribution networks, can also be applied to hydro's offer. Obviously, it will depend on how it is designed the sharing costs between generation, transmission, distribution companies and consumers.

#### *4.2.2.4 Sources of bid constraints*

There are certain aspects of the project and operation of the hydro power plants that can affect the bid values, as discussed below:

- Hydro with reservoir (hydro_wr) or hydro run-of-the-river (hydro_rr): Some hydros have the capability to store water and thus transfer energy from one period to another once the reservoir allows that. Differently, run-of-the-river hydros have so little or no water storage capability. In other words, they don't have reservoir or their reservoirs cannot provide neither multiannual, annual nor seasonal regularization. This is a physical constraint that can be incorporated in the hydros' bids. In order to consider this in every trading period, run-of-the-river hydros have to offer the exact amount of water that has flowed to their dam, otherwise they will have virtual spillages computed on their behalf (i.e. subtracted from their ERA).

- Unavailability factors: Basically the unavailability factors can be classified in two groups: "unavailability factor due to forced maintenance" and "unavailability factor due to scheduled maintenance". Both of them represent interventions of maintenance or repair teams, however the former is related to unexpected outages that can happen in the power plant, and the latter with expected outages planned by the staff of the company. The consideration of both unavailability factors into the rules of the Virtual Reservoir Model (VRM) makes sense because it stimulates the (real) unavailability to remain as low as possible, namely by doing an adequate maintenance. For example, if a power plant has two generation units, each one with 50 MW of installed capacity, and one of its units is unavailable due to an unexpected interruption of this equipment, physically this power plant can only produce 50 MW per hour. His bid is, consequently, constrained to 50 MW per hour along the duration of such unavailability.

*4.2.2.5 Conciliation of the VRM with other sources of generation*

Only hydros[48] will operate into the VRM. However, other generation sources contribute to supply the total demand. This section addresses the conciliation of the VRM with the other sources of generation. This conciliation is done considering that the implementation of the hydro short-term market (i.e. the VRM) is the main change in the Brazilian market design: the current centralized dispatch scheme and the existing regulatory framework applied to other generation sources are kept same.

In Brazil, thermal power plants sign availability type contracts, which means that they receive a fixed revenue whether dispatched or not, and when dispatched they receive a variable revenue according to their production, mainly to cover the cost of the fuel. This is because their fixed and variable costs are previously known by the ISO. The ISO beforehand knows these costs once they are components of their bids in the long-term public auctions (described in Section 3.2.1). Even though the thermal power plants don't really participate in a short-term market, the market knows their average variable costs. Thus, the hydros supply curve (built through their bids in the short-term market) can be conceptually extended in order to incorporate other bids, such as the bids (average variable costs) made by thermal power plants in public auctions. The resultant curve will be here called by the "global supply curve", and Figure 4.5 illustrates it. In this figure, the blue line represents bids from hydros in the short-term market and the red line denotes bids from thermal power plants in the public auctions.

[48] To recap, in Brazil hydros usually close contracts in the quantity type, so they commit to deliver a certain amount of energy and any difference between the bilateral contract and the effective production must to be automatically sold or bought in the MCP.

Regarding wind farms and solar PV, both technologies intrinsically have an Average Variable Cost (AVC) equal to zero since they use energy provided by the wind and sun, respectively, to produce electricity. Moreover, their marginal cost is equal to zero and, unlike hydropower plants with reservoir, these technologies alone cannot store energy in large scale for later usage. Finally, they usually participate in public auctions to get availability type contracts, such as thermal power plants. That being said, these technologies can also be incorporated in the "global supply curve" as bids at zero price (green line in Figure 4.5).

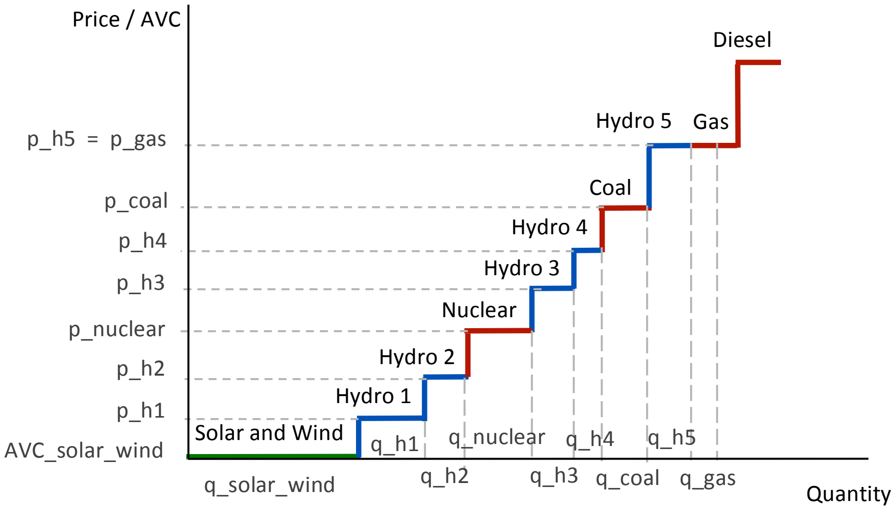


**Figure 4.5 – The global supply curve**

Figure 4.5 can then be decomposed in two supply curves. As explained in the beginning of Section 4.2, in VRM the ISO defines in the first place the physical amount of generation of each power plant. So, through this dispatch it is known the total demand to be supplied by all hydros ($Q_h$) and non-hydros ($Q_{nh}$). The sum of $Q_h$ and $Q_{nh}$ is equal to the total demand of the system ($Q_{total}$). Figure 4.6 illustrates these two supply curves: the graphic on the left represents the demand and the supply curve from non-hydros resources and the graphic on the right plots the demand and the supply curve from hydros resources.

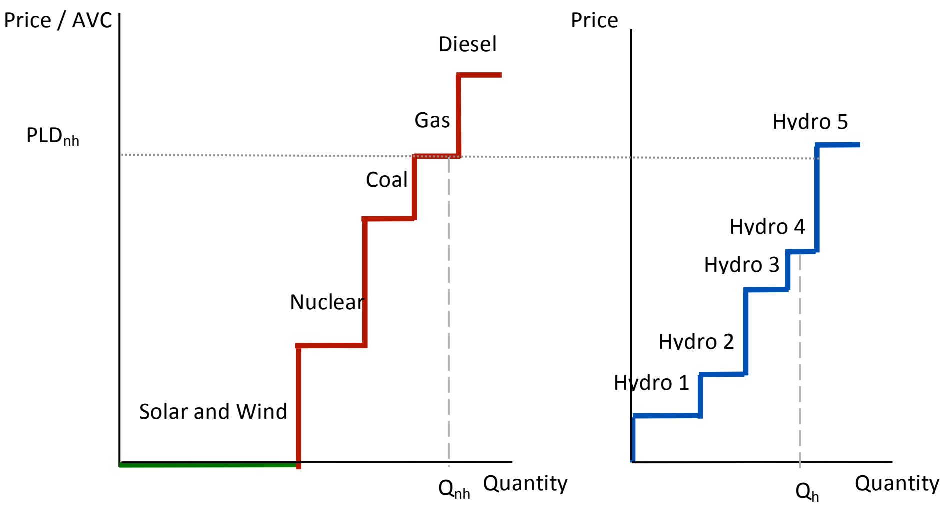


**Figure 4.6 – Two supply curves: from centrally dispatch and from hydro short-term market**

As shown in Figure 4.6, the price bid from hydros in their short-term market can be limited by the cost of the more expensive dispatched thermal power plant ($PLD_{nh}$), as the variable cost of the hydros can be seen as an opportunity cost linked with the variable cost of the last dispatched resource. In other words, the ceiling price or the maximum regulatory price (p_uplim) is equal to $PLD_{nh}$.

In the example of Figure 4.6, Hydro 4 had the last successful bid, which in fact was partially successful. Hydro 5 was the only one to offer a price bid (p_h5) equal to the maximum allowed price. Here the p_uplim is equal to the variable cost of the gas thermal power plant dispatched by the ISO (p_gas). Regarding Hydro 5, this situation may occur because in this framework hydros can bid according to their risk perception and considering their bilateral contracts. Supposing that Hydro 5 is expecting a water scarcity for the next periods, his evaluation of water savings is different from the others. Another assumption is that Hydro 5 is the only hydro that is not fully bilateral contracted. Consequently, price bids from Hydros 4, 3, 2 and 1 tend to be lower than price bids from Hydro 5 because the formers want to avoid having to buy electricity to deliver their commercial commitments if their bids are unsuccessful.

*4.2.2.6 Final short-term market price*

The final short-term price ($PLD_{final}$) is calculated as a weighted average considering the most expensive successful hydro price bid (the marginal hydro resource to supply $Q_h$) and the variable cost of the last non-hydro resource dispatched by the ISO (the marginal non-hydro resource to feed $Q_{nh}$). So, taking Figure 4.5 as an example, the final short-term market price is determined by equation 4.5:

$$\mathrm{PLD}_{final} = \frac{(\mathrm{p\_h4} \times Q_h) + (\mathrm{p\_gas} \times Q_{nh})}{Q_{total}} \tag{4.5}$$

Generalizing, the PLD_final is given by equation 4.6:

$$\mathrm{PLD}_{final} = \frac{PLD_{nh} \times Q_{nh} + PLD_h \times Q_h}{Q_{total}} \tag{4.6}$$

In these equations:

$PLD_h$: is the most expensive successful hydro price bid;

$PLD_{nh}$: is the variable cost of the last non-hydro resource dispatched by the ISO.

As it can be observed, the final short-term market price is a combination of the visions (perspectives, strategies and risk perceptions) from both the ISO and hydros, i.e., the final price reflects both the centralized dispatch and the market based on bids.

Besides, the hydros' freedom to influence the final price is limited by the value of the maximum regulatory price bid (PLDreg_uplim). To illustrate this issue in this research, two scenarios are considered in the simulations of the next chapter: (i) the market has high and fixed ceiling price throughout the year; or (ii) the ceiling price varies according to the last resource dispatched by the ISO. In the former case, prices from the hydro short-term market can be higher than the last resource dispatched by the ISO (which is the latter case), which can indicate a difference between the forecast of hydrological resources made by the ISO and the market agents, or even an exercise of market power by some players.

*4.2.2.7 Comparison between ISO's decision and agents' decision*

The analysis regarding the comparison between the decision taken by ISO and by agents and the evaluation of the ISO's performance (Figures 4.3 and 4.4) has to be performed after the elimination of variables that can bias the results, such as the amount of water physically withdrawn from the reservoir for flood control purpose. Since "flood control" is one of the ISO's concerns and obligations, which is not taken into account in the agent's decision process, it has to be excluded in order to avoid distortions in this comparison. This comparison should focus on the follow questions: "who is taking the best decision regarding the forecast of the water flows of the rivers?"; and, consequently, "who is better managing the reservoirs?". This should be done mainly focusing on virtual and real spillages throughout a certain period.

## 4.3 Modeling alternatives for understand generators' behavior

Considering that the VRM and its short-term market based on bids will operate as a liberalized wholesale electricity market, it is necessary to understand the behavior of the generation companies, especially regarding their bidding strategies. Thereby, numerous publications were published over the last few years to address this issue. [Li et al., 2011] classify the various models available in the literature for strategy bidding analysis in electricity short-term markets in four groups, as illustrated in Figure 4.7: (1) single generation company (Genco) optimization models; (2) game theory based models; (3) agent-based models (ABM); and (4) hybrid models.

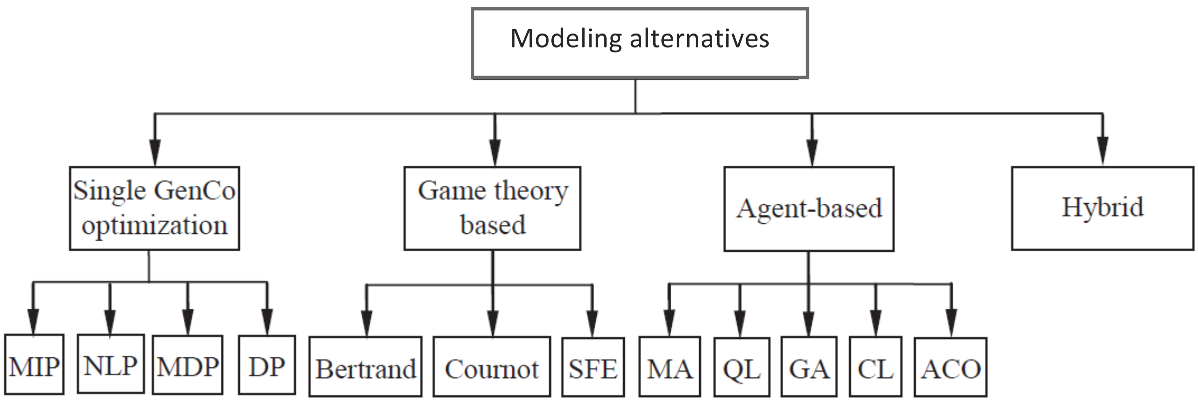


**Figure 4.7 – Modeling alternatives for bidding in electricity market [Li et al., 2011]**

The single generation company optimization models include a large number of formulations that use a wide range of mathematical programming methods such as Mixed Integer Programming (MIP), Nonlinear Programming (NLP), Markov Decision Process (MDP) and Dynamic Programming (DP). Formulations in this group typically optimize the bidding strategy for a single-market participant while ignoring or simplifying the behavior of other players.

Game theory models, also called equilibrium models, optimize the bidding strategies by investigating interactions between the players and analyzing economic equilibrium of the system. Typically, in a game, each player chooses the strategy from his own strategy set, then a payoff will be assigned to each player by the payoff function, and the solution can be reached via Nash equilibrium. Nash equilibrium is the strategy combination of all players in which no player can increase his payoff by changing his own strategy alone.

Different competition rules can also be adopted in game theory models: Bertrand competition (generation companies compete with one another by using prices as the strategic variables and ignore their capacity constraints); Cournot competition (generation companies compete by using quantities as strategy choices, under the assumption of having homogenous products, and the market clearing price is determined by the intersection of the aggregated supply and market demand curves); Supply Function Equilibrium – SFE (in such market, considering uncertain demands, participants prefer to set supply functions rather than competing in prices or quantities); and some other newly proposed competition rules (e.g. multi-period bidding markets under the assumptions of price-sensitive demands, and hourly bidding strategy according to degrees of risk aversion).

In the agent-based models (ABM), market participants are represented as agents with different bidding preferences and strategies, and they are enabled to use their past experiences to improve their behaviors. Each agent can also be adaptive, which means that it can develop its optimal bidding strategy by learning from his past experiences obtained from the direct interaction with the environment. This brings a new type of numerical analysis theory, which is categorized in terms of different learning algorithms such as, for example, model-based adaptation algorithms (MA), Q-Learning (QL), genetic algorithms (GA), computational learning (CL), and Ant Colony Optimization (ACO).

Generally, the agent-based modeling procedure can be described as follows [Weidlich & Veit, 2008]: (1) define the research questions to be addressed; (2) construct a model comprising an initial population of agents; (3) specify the initial model state by defining the agents attributes and the structural and institutional framework of the electricity market within which the agents operate; (4) make the model evolve over time without further intervention; (5) analyze simulation results and evaluate the observed regularities. Table 4.1 summarizes the features of the three types of models previously discussed.

Besides the above three major groups of modeling approaches, there are a few other methods developed recently for strategic bidding analysis, as the hybrid approach that combines multiple modeling methods like Lagrangian relaxation and genetic algorithms in order to generate a proper unit commitment scheduling and to derive the optimal supply curves [Yamin & Shahidehpour, 2003], and agent-based approach with game theory to study strategic collaboration among agents [Sueyoshi, 2010].

**Table 4.1 – Characteristics of the three main modeling alternatives [Li et al., 2011]**

| Models | Characteristics |
|---|---|
| Single generation company optimization | Developing optimization models to describe the entities in the electricity market with the objective of finding an optimal solution:<br>• Well-established and solid mathematical foundation;<br>• Generally focusing on one specific player in the system by simplifying the rest of the system as a set of exogenous variables;<br>• Usually modeling no aspects of players intelligent behaviors;<br>• Difficult to model the complex, uncertain and dynamic systems or analytically derive the optimal bidding strategy. |
| Game theory | Modeling the electricity market as a game and mathematically capturing the players' behavior in the game where one players success in making choices depends on the others choices:<br>• Usually mathematically well-defined, involving a set of game players, a set of bidding strategies, and a specification of payoffs for each possible combination of bidding strategies;<br>• Analyzing the economic equilibrium of the market by focusing on the players interactions;<br>• Capable of providing analytical rationale and explanation on how strategic bidding behaviors affect the market power and profits;<br>• All players are assumed to be rational, which does not generally hold in the reality;<br>• The frustrating issue of multiple equilibrium often occurs in solving the problem;<br>• Also, it is limited by the requirement of common knowledge on all generation companies' real generation costs. |
| Agent-based | Modeling the complex electricity market as collections of rule-based agents interacting with one another dynamically and intelligently, simulating human beings' behavior to make optimal bidding strategies:<br>• Only a few simple rules are specified for and followed by various agents that are situated in the network and that behave intelligently in the system;<br>• Agents usually have and only require imperfect and local information and visibility;<br>• No centralized control or planning is required although random elements often exist either among agents or in the system;<br>• Agents can interact with each other directly or through the environment, resulting in complex emergent global behavior of dynamic-equilibrium and adaptation;<br>• More flexible, robust, and easily implemented compared with analytical approaches;<br>• Capable of capturing the details about agents behaviors, which is helpful in figuring out the relationships between individual decisions and system behavior;<br>• Capable of modeling the dynamics of systems that are not in equilibrium;<br>• The underlying mathematical foundation is still not well developed;<br>• Requiring computation-intensive procedures. |

In summary, while the single generation company optimization models typically optimize the bidding strategy for a single-market participant (ignoring or simplifying the behavior aspects of other players), the game theory models (or equilibrium models) assume that players have all relevant information about the other players' characteristics and behavior, and they also disregard the consequences of learning effects from daily repeated interaction [Rothkopf, 1999]. On the other hand, ABM is one appealing new methodology that has the potential to overcome some of the aforementioned shortcomings of optimization or equilibrium modeling methods [Weidlich, 2008].

## 4.4 ABM with Q-learning applied to electricity markets

To simulate the behavior of the hydropower plants in the short-term market based on the VRM, an ABM was developed using Q-Learning. As previously discussed, among the modeling alternatives for strategy bidding analysis, ABM is highlighted because it provides an environment where agents can mimic the human behavior to dynamically and intelligently interact with each other. As pointed out by [Weidlich, 2008], the concept of (computational or software) "agents" stems from the fields of Artificial Intelligence (AI) and Multi-Agent System (MAS). In the developed model these agents learn how to act optimally using the reinforcement Q-learning algorithm.

A reinforcement learning inspired on psychological theory is an active area of the artificial intelligence [Kaelbling et. at., 1996]. Through trial and error search, reinforcement learning techniques allow the agent to map each situation into action [Sutton & Barto, 1998] and, in doing so, it learns the policy of what to do by finding the optimal output for each possible input. The Q-learning algorithm was initially proposed by [Watkins & Dayan, 1992] and it is nowadays one of the most adopted reinforcement machine learning techniques. Q-learning can be classified as a free model once it doesn't need an explicit model of its environment. Instead, the knowledge about the optimal policy increases while a history of interaction with the environment is being built.

The Q-learning is a useful algorithm for solving Markov decision problems, and this is done by evaluating the payoff for a given state-action pair. So, the Q-learning matrix is composed by cells known as Q-values. Thus, Q-values are calculated for each pair of state (s) and action (a), and therefore it can also be described as Q(s, a). As the Q-learning focuses on the impacts of rewards (r) on the choices of actions in each state, the Q-values are obtained by a function that provides the expected utility of taking a given action in a given state. The function used to update the Q-learning matrix is given by (4.7).

$$Q(s_{t,}a_t) \leftarrow Q(s_{t,}a_t) + \alpha.\{r_t(s_{t,}a_t) + \gamma.max_a Q(s_{t+1,}a_t) - Q(s_{t,}a_t)\} \qquad (4.7)$$

The parameter α is the learning rate, which reflects the degree to which recently learned information will override the old one (α equal to 0 makes the agent not learn, while equal to 1 induces the agent to consider only the most recent information). The parameter γ entitles the discount factor that determines the importance of future reinforcements (γ equal to 0 makes the agent myopic by only considering current rewards, while values closer to 1 turn distant rewards more important). The expression $max_aQ(s_{t+1}, a)$ represents the best the agent thinks it can do in state $s_{t+1}$.

A classical structure of the Q-learning algorithm used by an agent is presented below.

Step 1 Initialization of the Q-learning matrix;

Step 2 Recognition of the current state;

Step 3 Selection of an action according to a certain policy;

Step 4 Agents' interaction within the environment;

Step 5 Assignment of the reward;

Step 6 Update of the Q-leaning matrix;

Step 7 While not occur convergence, return to Step 2.

First, it is initialized the Q-learning matrix, which operate as the agent's brain emulating its memory and learning functions. Then, following a certain policy, agents decide what actions are taken. The interaction of the agents happen as a game played with joint actions. After that, the rewards (negative or positive) are computed. Finally, after observing the subsequent state the Q-learning matrix is updated.

This sequence of steps should be repeated until the algorithm converges. So, in order to allow agents to acquire knowledge from past actions and properly decide for upcoming actions, it must be guaranteed that actions have been tried a sufficient number of times to be able to correctly assess their expected reward. At the end of this process it is expected that the agents have mapped (and valuated) each situation, and so they will be able to optimize their actions.

Several authors have been modeling and performing simulations using ABM with Q-learning in the power sector. As pointed out by [Lau et. al., 2013], this is because these simulations offer the possibility of modeling agents that learn and adapt to their environment, and thus they can be a useful tool that supports analysis of a complex system such as electricity markets. [Krause & Anderson, 2006] tested a simulator with ABM and Q-learning for evaluating different congestion management methods of transmission networks in liberalized electricity markets. Their results have shown different allocations of market power for the different congestion management schemes.

Methods like game theory require a lot of information about the other market players and the market itself, and in real markets only a small amount of information (such as the spot price) is available for all participants. Bearing this in mind, [Naghibi-Sistani et. al., 2006] compared the game theory approach with a ABM with Q-learning algorithm. They found out that, while the game theory approach requires a lot of information to be able to identify the best bidding strategy, the proposed method using Q-learning enables participants to find the optimal strategy using only those few items of information available to all participants in real market places.

[Krause et. al., 2006] also worked to distinguish an ABM and an analysis based on Nash equilibrium. These authors compared these two approaches considering a network-constrained pool market. Assuming an oligopoly market with three generators and three constant and inelastic loads, they analytically computed the Nash equilibrium of the system and then compared the results with those obtained by the agent-based approach. Considering the case of one Nash equilibrium, these authors showed that there is high likelihood for the Q-learning algorithm to indeed converge to this equilibrium.

[Yu et. al., 2010] used an ABM to evaluate rules that were proposed to mitigate market power in the California electricity market. Using the ABM empowered by Q-Learning, it is found out that agents are able to capture the dynamic interaction between strategic bidding market participants. Results show that major generation owners who interact with each other in similar scenarios easily learn to implicitly collude.

Focusing on capacity withholding and the emergence of tacit collusion among the market participants, [Tellidou & Bakirtzis, 2007] performed a study on the spot electricity market running a modified version of typical Q-learning. The energy market is formulated as a repeated game, where each stage of the game corresponds to an hourly energy auction that is cleared using the locational marginal prices. Furthermore, in all stage game repetitions the nodal load demand and the transmission system conditions remain the same. Test results on a two-node power system with two and eight competing generator-agents demonstrate the development of tacit collusion among generators even under competitive conditions.

An interesting comparison was performed by [Trinh et. al., 2013]. These authors applied two approaches to a market test suite that is based on a fictional European wholesale electricity market. The first approach is a laboratory experiment where master students from the engineering department of the KU Leuven represent generators in this market. In the second one, generators are represented by computational agents in an ABM with a reinforcement learning algorithm. Quantitative results obtained from this research show that computational agents achieved higher generators' profits than students in the given market simulation. However, they indicate that aspects like cognitive issues, expertise and motivation, as well as the number of rounds, sample size and freedom of choice can affect the outputs of this comparison.

As a result of the research conducted by [Guo et al., 2004] concerning the balance between exploration and exploitation of the reinforcement learning process, a Q-Learning algorithm with a Simulated Annealing (SA) was proposed. In this framework, exploration means to gather more information by experimenting new alternatives and discovering new possibilities, and exploitation refers to refine the old certainties, i.e. to take the best decision given current information. An appropriate algorithm has to deal with this trade-off and help the agent to gather enough information to take the best overall decisions. Given that the SA-Q-learning algorithm has been very promising by improving the ability of the agent to acquire new knowledge and avoiding a decrease of performance, it was adopted by [Bakirtzis & Tellidou 2006], [Tellidou & Bakirtzis, 2007], [Wang, 2009] and [Bach & Yao 2012] in their modeling of electricity short-term markets.

The SA-Q-learning algorithm guides the agent to choose the action that seems the best ($a_{policy}$). However, it also conducts to other action ($a_{rand}$), randomly chosen. The SA-Q-learning algorithm can be described as follows.

(1) Define the initial value of the temperature (Temp) of the Simulating Annealing;

(2) Select an action arbitrarily ($a_{rand}$);

(3) Select an action according to a greedy policy ($a_{policy}$) where, for the given state s, the highest Q(s, a) is picked, i.e.:

$$\boldsymbol{a_{policy}} = \mathbf{arg}\, \boldsymbol{max_a}\, \boldsymbol{Q(s, a)} \tag{4.8}$$

(4) Generate a random value ε ∈ (0, 1);

(5) Then, if:

$$\boldsymbol{\varepsilon} < \mathbf{e}^{\frac{\mathbf{Q(s,a_{rand})} - \mathbf{Q(s,a_{policy})}}{\mathbf{Temp}}} \tag{4.9}$$

- Chose action equal to $a_{rand}$

(6) Otherwise:

- Chose action equal to $a_{policy}$

(7) Adopt a temperature-dropping rule able to ensure a slow decay of the temperature factor along the algorithm. Usually it is used the geometric scaling factor rule as indicated below:

$$\boldsymbol{Temp_t} = \boldsymbol{\phi}.\boldsymbol{Temp_{t-1}} \quad , \mathbf{t} = \mathbf{1}, \mathbf{2}, \mathbf{3}, \ldots \tag{4.10}$$

$\Phi$ is a constant close to 1

## 4.5 The learning algorithm developed to the VRM

In this research, agents of the ABM represent hydro companies that prepare their bids taking into account the level of the (virtual) reservoir, the amount of energy committed through bilateral contracts, and month of the year, which is associated with the water inflows, the hydro short-term market ceiling price and the demand to be supplied by hydros.

Their goal is (i) to avoid negative exposures in case of ending up providing through their successful bids an amount of energy lower than the bilateral contracted, and (ii) to get extra profit in the short-term market when there is more energy into the reservoir than the required to comply with the bilateral contracts. In other words, agents have to manage their bilateral contracts through their bids in the short-term market to address the risk of exposition, and manage their reservoirs, saving and using water throughout the year in an appropriate way, in order to maximize their profit.

Furthermore, they are goal-oriented learners using the Q-learning algorithm. Thereby, for a giving Markov decision process, agents continually interact with their environment, receive feedback (rewards or punishments) from it, and search for the most profitable action considering their past experience. In other words, at each time step t the agent is in some state $s_t$, chooses any action that is available in state $s_t$, receives a corresponding reward $r_t$, and moves into a new state $s_{t+1}$. Thus, in Q-learning it is imperative to carefully structure the set of states S = {$s_1$, $s_2$, … , $s_n$}, actions A = {$a_1$, $a_2$, … , $a_n$} and rewards $r_t(s_t, a_t)$. In addition, in order to adequately balance the capacity not to converge to local optimal and the acceleration of the learning process, the Simulated Annealing (SA) algorithm is included into the developed algorithm as detailed in [Guo et al., 2004] and addressed in the previous section.

An overview of the entire algorithm is provided in Figure 4.8. In brief, to simulate the proposed market rules the algorithm gets from the ISO physical dispatch procedure the total demand to be supplied by non-hydros ($Q_{nh}$) and by hydros ($Q_h$), and the variable cost of the last non-hydro dispatched unit ($PLD_{nh}$). It also requires information about ex-ante bilateral contracts ($qCE_t$) for each account period, i.e. the amount of energy that must be endured in the hydro short-term market by the bids.

Other input data is as follows: the natural affluent energy that flowed in period *t* to the hydro cascade ($NAE_t$), from which a fraction is allocated to each hydro giving their physical guarantee (PG); the reservoir capacity (RC), and the virtual reservoir level or energy right account ($ERA_{start}$) in its initial stage. This algorithm is run in each account and settlement period. In the simulation performed in the thesis, this period is equivalent to a month.

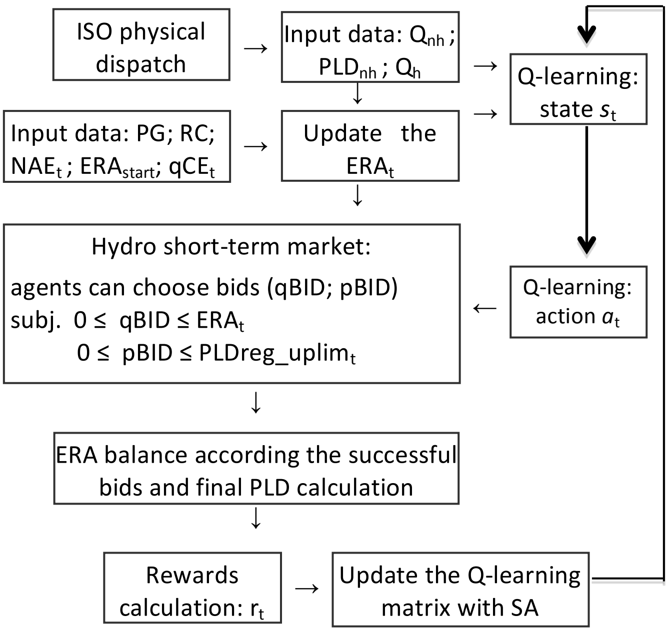


**Figure 4.8 – Overview of the developed algorithm**

After having all data input in the system, $ERA_t$ is updated with the due deposit ($DEP_t$), resulting in the balance account equal to $ERAadep_t$ (i.e. ERA after deposit). Then it is checked the occurrence of spillage (if $ERAadep_t$ > RC) and the balance account ends up with $ERAaspill_t$ (which means ERA after spillages). At this stage, the Q-learning algorithm identifies the current state $s_t$, and prepares the actions $a_t$. In other words, it is chosen the most adequate pair of quantity bid (qBID) and price bid (pBID) according the learning process that hydros undergo.

The hydro short-term market takes place considering the remaining demand $Q_h$. In the ABM this is the stage where agents interact with the environment. Bids can be done once respected the following constraints: the quantity bid (qBID) is limited by the available ERA balance; and the price bid (pBID) is limited by a maximum regulatory price ($PLDreg\_uplim_t$). Then, the bids are sorted considering the pBIDs, the successful bids are then identified, and the ERA is updated. The clearing price rule is adopted to define the final price of the hydro short-term market ($PLD_h$), and the final short-term market price ($PLD_{final}$) is determined as previously indicated by equation 4.6. With these outputs the rewards of the Q-learning are processed (as described in Sections 4.5.1 and 4.5.2), and the Q-learning matrix of each hydro is updated taking into consideration the current and the next state, and the action taken (as described in equation 4.6).

Agents are allowed to make two bids at the same time in each transaction period. The first bid (BID1) addresses the need to comply with bilateral contracts, i.e. agents have to learn the best strategy to sustain bilateral contracts and avoid or minimize the exposed positions in the short-term market. In the second bid (BID2) agents are allowed to manage their reservoirs in order to optimize the leftover stored energy. That is, considering water management in the reservoir throughout the year, in BID2 the agent's focus is to get extra profit in the short-term market when there is more energy in the reservoir than the one need to comply with the bilateral ex-ante contracts.

Thus, the algorithm is structured focusing on both the hydros' flexibility to comply with bilateral contracts (through BID1) and the hydros' flexibility to manage their leftover energy (through BID2). Accordingly, each agent runs in simultaneous two different Q-learning algorithms in order to achieve the two goals described above. The two following subchapters describe the three main concepts used in the Q-learning algorithm (state, action and reward) for the two mentioned processes of bid formulation (BID1 and BID2)

### 4.5.1 BID1: flexibility to endure bilateral contracts (minimizing risk of exposition in MCP)

Regarding BID1, the state space of Q-learning is divided in three: state *s*1, when the amount available into the ERA is larger than the ex-ante contract ($qCE_t$); state *s*2, when ERA balance is equal or lower than $qCE_t$; and state *s*3, if $qCE_t$ is equal to zero.

Moreover, it is possible to offer twelve different bids (actions), each one formed by a pair (qBID, pBID). The action space is formed by qBIDs equal to zero, 100% of the ERA, or 100% of the $qCE_t$, depending on the state. The pBID can be 100%, 75%, 50%, 25% or 0% of the maximum allowed bid price for the account period ($PLDreg\_uplim_t$).

Both the state and action spaces are illustrated in Table 4.2, which corresponds to the Q-learning matrix of BID1. Note that some actions are just allowed for a specific state (white cells in Table 4.2).

**Table 4.2 – Illustration of the Q-learning matrix: BID1**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **States** | ERA > qCE | ***s1*** | | | | | | | | | | | | |
| | ERA ≤ qCE | ***s2*** | | | | | | | | | | | | |
| | qCE = 0 | ***s3*** | | | | | | | | | | | | |
| | | | **a1** | **a2** | **a3** | **a4** | **a5** | **a6** | **a7** | **a8** | **a9** | **a10** | **a11** | **a12** |
| pBID (% of $PLDreg\_uplim_t$) = | | | 0% | 100% | 100% | 75% | 50% | 25% | 0% | 100% | 75% | 50% | 25% | 0% |
| qBID = | | | 0 | | 100%. ERA | | | | | 100% . qCE | | | | |
| | | | **Actions** | | | | | | | | | | | |

The reward is given by the difference between the successful quantity bid ($qBIDsuc_t$) and the amount committed through contracts for that period ($qCE_t$), as shown in equation 4.11. This reward was conceived to induce the agent to avoid negative exposures regarding his bilateral contracts.

$$reward\_BID1_t = qBID1suc_t - qCE_t \tag{4.11}$$

### 4.5.2 BID2: flexibility to manage the leftover energy (maximizing profit from MCP)

For the second bid (BID2), the state space of the Q-learning is organized in twelve states, one for each month of the year.

Moreover, it is possible to select an action among twenty-seven different bids (actions), each one formed by a pair (qBID, pBID). The action space is formed by qBIDs equal to 0% (a1 and a2), 20% (from a3 to a7), 40% (from a8 to a12), 60% (from a13 to a17), 80% (from a18 to a22) and 100% (from a23 to a27) of the ERAaBID1. ERAaBID1 is the available energy in the virtual reservoir after the first bid (BID1). The pBID, the same as BID1, can be 0%, 25%, 50%, 75% or 100% of the maximum allowed price bid for the account period ($PLDreg\_uplim_t$).

Both the state and action spaces are illustrated in Table 4.3, which corresponds to the Q-learning matrix of BID2.

**Table 4.3 – Illustration of the Q-learning matrix: BID2**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **States** January | ***s1*** | | | | | | | | | | | | | |
| … | **…** | | | | | | | | | | | | | |
| December | ***S12*** | | | | | | | | | | | | | |
| | | **a1** | **a2** | **a3** | **a4** | **a5** | **a6** | **a7** | **…** | **a23** | **a24** | **a25** | **a26** | **a27** |
| pBID (% of $PLDreg\_uplim_t$) = | | 0% | 100% | 0% | 25% | 50% | 75% | 100% | … | 0% | 25% | 50% | 75% | 100% |
| qBID = | | 0 | | 20% . ERAaBID1 | | | | | … | 100% . ERAaBID1 | | | | |
| | | **Actions** | | | | | | | | | | | | |

When the hydro is run-of-the-river type (discussed in Section 4.2.1.4), the company always choose the action a23 (qBID equal to 100% of the ERAaBID1 and pBID equal to zero). This is done since this kind of hydro cannot manage the water stored in the reservoir. So, in each period they have to use the total amount available (otherwise they will have spillage) and offer it at a price equal to zero (his marginal cost is zero and hydro is modelled as price taker within the uniform pricing of the VRM). Then, there is no need to build a Q-learning matrix for run-of-the-river hydros.

For hydros with reservoir, their reward is given by equation 4.12. As detailed below, the equation leads the agent to pursuit the optimal management of the reservoir at the same time he has to adjust his strategy in order to maximize his profit in the short-term competitive market.

$$reward\_BID2_t = factor_{goalt} \times (qBID2suc_t + ERAaBID2_t) \times PLD_{finalt} \tag{4.12}$$

In equation 4.12, the $factor_{goal\_t}$ is the adjustment factor concerning the reservoir level goals, $qBID2suc_t$ is the successful quantity BID2, and $ERAaBID2_t$ is the leftover energy in the reservoir after BID2 in period t. The value of the $factor_{goal\_t}$, which is a crucial element of this equation, is obtained after solving the linear programming problem shown in (4.13).

$$\text{Max } f = \sum_{t=1}^{12} qBID2'_t \,.\, pBID\_uplim_t + A.\sum_{t=1}^{12} qBID1'_t + B.ERAaBID2'_{t=12} \tag{4.13}$$

where:

$$A = pBID\_uplim_{max} \,.\, \sum_{t=1}^{12} DEP_t \tag{4.14}$$

$PLDreg\_uplim_{max}$ = maximum monthly PLDreg_uplim of the year (4.15)

$$B = 100\,.\,A \tag{4.16}$$

Subject to:

$$ERAaBID1'_t = D - qBID1'_t \quad , \text{ for t = 1} \tag{4.17}$$

where:

$D = ERAstart_1 + DEP_1$ , if $ERAstart_1 + DEP_1 < RC$ (4.18)

$D = RC$ , if $ERAstart_1 + DEP_1 > RC$ (4.19)

$$ERAaBID1'_t = ERAaBID2'_{t-1} + DEP_t - qBID1'_t \quad , \text{ for t = 2 until 12} \tag{4.20}$$

$$ERAaBID2'_t = ERAaBID1'_t - qBID2_t \quad , \text{ for t = 1 until 12} \tag{4.21}$$

$$ERAaBID2'_t \leq 0{,}25\,.\,RC \quad , \text{ for t = 12} \tag{4.22}$$

$$qBID1'_t \leq qCE_t \quad , \text{ for t = 1 until 12} \tag{4.23}$$

$$0 \leq qBID1'_t\, , qBID2'_t\, , ERAaBID1'_t\, , ERAaBID2'_t \leq RC \tag{4.24}$$

The variables of the problem are $qBID1'_t$, $qBID2'_t$, $ERAaBID1'_t$ and $ERAaBID2'_t$, and all of them must be greater than or equal to zero and lower than or equal to RC (equation 4.24). The apostrophe of these variables indicates that they represent optimal values resulting from the linear programming. The index t indicates the month of the year, and the optimization run one entire year. As $qBID1'_t$ must be as close as possible to their contract ($qCE_t$), the value of A in the objective function encourages high values of $qBID1'_t$, while the equation 4.23 limits the maximum values of $qBID1'_t$. Similarly, the value B pushes the reservoir to end up the year with a level equals to or as close as possible to its target. Here, this target is embodied by equation 4.22, i.e. at 25% of the reservoir capacity (RC). Afterward, the equation "$\Sigma qBID2'_t$ x $PLDreg\_uplim_t$" presents into the objective function represents the revenue obtained in the VRM when the company sell $qBID2'_t$ at the ceiling price ($PLDreg\_uplim_t$).

The variable D is included in the linear programming just to limit the occurrence of values (sum of ERAstart and DEP) above RC in the first month. If this occurs, it represents an unmanaged spillage (both $ERAstart_1$ and $DEP_1$ are exogenous data of the optimization). This limitation is imposed only to month 1 once the optimization of the remaining months will ensure by itself that no spillages occur[49]. At the end, the linear programming formulated at this way will safeguard results where all the manageable spillage will be avoided.

Finally, once the ERAaBID2'$_t$ is known, it is possible to compute the goal level of the virtual reservoir at the end of the trading period (Reservoir_level$_{goal_t}$). This calculation is shown by equation 4.25.

$$\text{Reservoir\_level}_{goal\_t} = \frac{ERAaBID2_t}{RC} \tag{4.25}$$

As can be noted, this optimization outputs the Reservoir goal level in each period t, which is the input data to compute factor$_{goal_t}$. The factor$_{goal_t}$ works according a target band system that embodies a hyperbolic function. That is, if the difference between the current reservoir level and its target is into the narrowest band, the value of the factor$_{goal_t}$ is the largest possible; however, the value of the factor$_{goal_t}$ reduces and tends to zero as this difference increases.

In the algorithm it was adopted the following rule: factor$_{goal_t}$ is equal to 1 if the current level of the reservoir is into a band where the median is the goal level and its length is equal to ERAaBID2$_{goal_t}$ plus 10%, and it gradually reduces to 0.9, 0.7, 0.4 and zero as the current level of the reservoir moves away from the goal range.

The value of the factor$_{goal_t}$ giving the distance from the goal level is presented in Table 4.4.

**Table 4.4 – Targeting system by bands and value of the factor$_{goal_t}$**

| Bands | factor$_{goal_t}$ value |
|---|---|
| up_goal = ERAaBID2$_{goal_t}$ + 5% | 1.0 |
| low_goal = ERAaBID2$_{goal_t}$ - 5% | |
| close1_up = up_goal + 10% | 0.9 |
| close1_low = low_goal - 10% | |
| close2_up = up_goal + 20% | 0.7 |
| close2_low = low_goal - 20% | |
| close3_up = up_goal + 30% | 0.4 |
| close3_low = low_goal - 30% | |
| far_away > up_goal + 30% | 0.0 |
| far_away < low_goal - 30% | |

To give an example, let's suppose that the Reservoir_level$_{goal_t}$ is 32% for a trading period. After offering BID1 (qBID1, pBID1) and BID2 (qBID2, pBID2), the hydro ends up with a reservoir level

[49] To avoid the occurrence of spillage in the other eleven months, the month deposits (DEP$_t$) most be lower than or equal to the reservoir capacity (RC). Again, if DEP$_t$ > RC, then unmanaged spillage will occur. So, before run the linear program there is a procedure to convert any DEP$_t$ greater than RC in RC.

of 61% of its capacity ($Reservoir\_level_{actual\_t}$ = 61%). In this case, as shown in Figure 4.9, the $factor_{goal\_t}$ to be used in equation (4.13) is 0.4.

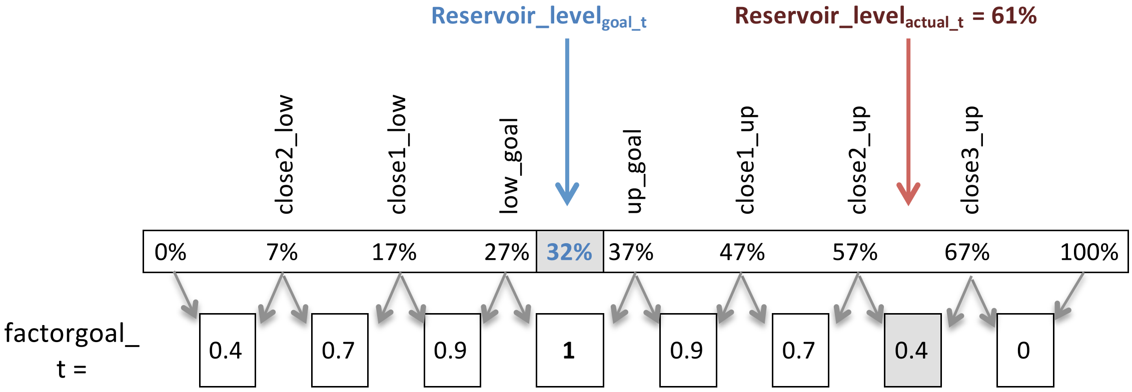


**Figure 4.9 – Example to illustrate the choice of the $factor_{goal\_t}$**

Last (but still regarding equation 4.13), the following should be detailed. There are periods (near the starting period of low water flows) when it is better to save water. In this case, it is expected to use low qBID2suct, which results in high $ERAaBID2_t$. Therefore, agents should value the $ERAaBID2_t$ more than $qBID2suc_t$. Nevertheless, in certain occasions (e.g. when there is water scarcity and prices are high) the best action is to offer large $qBID2suc_t$ (at a higher price), decreasing the level of the $ERAaBID2_t$.

The decision whether to value $qBID2suc_t$ more than $ERAaBID2_t$ and vice-versa is guided by the $factor_{goal\_t}$. If the agent offers a large qBID when it should be low, the current level of the reservoir will be away from the goal level, and the reward will penalize the agent through the $factor_{goal\_t}$. Even if there is a successful qBID2, the penalty can be so large that the reward will be zero (when $factor_{goal\_t} = 0$). Finally, the $PLD_{finalt}$ in equation (4.13) will boost the learning agent, reinforcing the periods of high or low price (i.e. low or high water inflow).

### 4.5.3 An overview of the update process of ERA balance

Within one trading period the ERA is updated several times. First, due the occurrence of inflows, it is credited in each hydro account its corresponding deposit, and the ERA ends up as $ERAadep_t$ (equation 4.26). Then, if $ERAadep_t$ is higher than the RC, the ERA undergoes a debt due a virtual spillage ($VS_t$) (equation 4.22), resulting in the next update of the ERA balance: $ERAaspill_t$ (equations 4.27 and 4.28).

$$ERAadep_t = ERA_{start} + DEP_t \tag{4.26}$$

$$VS_t = ERAadep_t - RC \quad , \text{ if } ERAadep_t > RC \tag{4.27}$$

$$ERAaspill_t = ERAadep_t - VS_t \tag{4.28}$$

The $ERAaspill_t$ is the amount of energy available for BID1, and the $ERAaBID1_t$ is the amount of energy available for BID2 (equation 4.29). The last account update occurs considering all the two successful bids of the hydro ($qBID1suc_t$ and $qBID2suc_t$, if applicable), and the hydro ends the trading period with $ERAaBID2_t$, which is equal to the available amount of energy that hydro will have in the beginning of the next trading period, i.e. $ERAstart_{t+1}$ (equation 4.30).

$$ERAaBID1_t = ERAaspill_t - qBID1_t \tag{4.29}$$

$$ERAaBID2_t = ERAaspill_t - qBID1suc_t - qBID2suc_t = ERAstart_{t+1} \tag{4.30}$$

## 4.6 Final remarks

In order to overcome the concerns discussed in Section 3.3 (i.e. efficiency of the energy resource; security of supply; and flexibility to endure contracts), a new market design based on the concept of virtual reservoirs was proposed. This market design aims at maintaining the current levels of efficiency and security, while increasing the level of flexibility regarding the commercial behavior of the agents. In the Brazilian case, this flexibility is achieved by replacing the MRE and the seasonalization processes by the Virtual Reservoir Model (VRM).

According to the proposed market framework two worlds operate simultaneously: one associated with the power system considering physical effects; and another related to the settlement system. The management of (virtual) reservoirs is under the responsibility of each hydro, which can (virtually) save water according to their own risk perception, but the (real) operation of the physical system is not affected. Thus, the efficiency of the hydro cascade operation is ensured and the current level of the security of supply is maintained.

Other advantages of this market design can be noted as follows. First, it promotes an increased transparency related with the computational models used by the ISO to run the centralized dispatch. Given that the codes associated with this software package are under intellectual property rights, inconsistencies in these algorithms have a huge impact within the entire sector. A market design that combines a centralized dispatch and a market based on bids can increase the confidence of sector. Second, with both the physical and virtual dispatch operating in parallel, it is possible to promote an analysis of the ISO performance based on comparisons of the ISO's decisions and agents' decisions.

Section 4.2.2.5 dealt with the implementation of the VRM taking into consideration the permanence of current Brazilian central dispatch. The hydro short-term market based on VRM fits the other aspects of the current Brazilian electricity market design, notably regarding the present regulatory framework applicable to other resources such as thermal, wind and solar power plants (e.g. long-term bilateral contracts with clauses regarding fixed and variable cost payments). In this case, the VRM was designed to take place after the ISO dispatch. In other words, first the ISO decides the $Q_h$ (total demand to be supplied by hydros), and then hydros compete to supply this $Q_h$.

In addition, the VRM is a flexible and comprehensive concept, and its employment can be done in both a centralized (as the Brazilian case) or decentralized dispatch scheme. If otherwise we adopt it in a decentralized dispatch, the VRM can also be applied in power system with large penetration of hydros as follows: i) "all" sources of generation participate in a unique short-term market based on bids; ii) by doing so, it is the market (not the ISO) that decides the total generation to be supplied by each source, including hydros; iii) hydros' bids in the short-term market can operate based on the VRM (i.e. their bids are virtual ones and have commercial replications, as presented Section 4.2); iv) later, considering the total successful bids coming from hydros ($Q_h$), the ISO can, once respecting the $Q_h$, rearrange these bids (in order to optimize the hydro cascade) and physically dispatch the hydros (with physical replications); v) the other generation sources are physically dispatched according to their own successful bids, as it happens in a classical short-term market based on bids.

Regarding the algorithm proposed to simulate the behavior of the market participants within this new market design, it was used an ABM with Q-learning. The developed algorithm allows agents to offer two bids in each trading period, and each bid has a different purpose. BID1 aims at allowing the hydro to comply with its ex-ante bilateral contracts, while BID2 goes beyond by allowing the management of the reservoir concerning the maximization of the profit regarding the leftover energy from BID1. These two features are incorporated into the algorithm through the combination of a goal-oriented scheme, built through the mentioned linear programming, with a goal-oriented learner from the Q-learning.

The whole process of agent-based modeling contains several iterations and feedback loops between the target system and its computational implementation [Weidlich, 2008]. Indeed, the algorithm presented in Section 4.5 is the 12th version of ABM developed in this thesis, i.e. several alternatives of the ABM with Q-learning were developed before this final one. Afterwards, the next step of the ABM modeling has to address the following question: Does the model represent the real world in an appropriate way?

The next chapter is devoted to test and validate the proposed algorithm. In order to do that, a case study is run with different scenarios to help gaining insight regarding the behavior of the agents. Finally, the second part of Chapter 5 is dedicated to simulate the Brazilian hydros participating in the short-term electricity market under the rules of the Virtual Reservoir Model.

# Chapter 5 – Simulations, Results and Discussion

This chapter is organized in two parts. The first one (Section 5.1) focuses on testing and validating the algorithm described in Section 4.5. This algorithm was written in Matlab bearing in mind the analysis of the market participants' behavior using the Virtual Reservoir Model (VRM). The VRM was designed as an Agent Based Model (ABM) where agents are adaptive and use Q-learning as the core of the mentioned algorithm. The second part (Section 5.2) is devoted to report the results of the simulation of the Brazilian electricity market operating under the proposed market design.

## 5.1 Validation of the algorithm

In order to test and validate the algorithm, a Case Study was constructed with four hydro stations that are characterized in Table 5.1. The hydros' features embody the diversity needed to perform the assessment. In this example, hydros compete to supply a demand $Q_h$ that varies along one year. Since in Brazil the settlement process occurs monthly, the current version of the hydro short-term market also operates on a monthly basis.

**Table 5.1 – Characteristics of the hydros (MWaverage)**

| Hydro | H1 | H2 | H3 | H4 |
|---|---|---|---|---|
| Physical guarantee (PG) | 125 | 100 | 50 | 225 |
| Reservoir capacity (RC) | 500 | 400 | 200 | 900 |
| ERA in t =1 | 0 | 0 | 0 | 0 |

The simulations that were perfomed considered many different scenarios regarding:

- Three weather patterns: *high*, *medium* and *low* water level inflows;
- Three level of bilateral contract commitments: qCE equal to 100%, 50% and 0% of the physical guarantee;
- Two types of seasonalization of the bilateral contracts: *FLAT*, where the annual energy committed through contracts is monthly distributed in equal amounts; and *NAE*, in which the annual amount is allocated bearing in mind weights determined by the inflow of water ($NAE_{total}$); and
- Two ceiling price rules: different monthly ceiling price in which the price limit is equal to the variable cost of the last non-hydro station dispatched by the ISO (*PLDnh*); and a fixed ceiling price equal to 827 R$/MWh[50], representing the operating cost level of the most expensive thermal power plants in Brazil (*Fixed*).

In Table 5.2 we can observe the monthly demands ($Q_{total}$, $Q_{nh}$ and $Q_h$) for the hydrological regimes. The *high* water flow pattern was shaped considering that the annual average of the $NAE_{total}$ exceeds 25% of the sum of hydros' physical guarantees. So, the indicator GSF (Generating Scaling Factor) computed using equation 3.6 (Section 3.3.3) is equal to 1.25. In

[50] This value is in accordance with the maximum regulatory short-term market price approved by the Brazilian Electricity Regulatory Agency (ANEEL) through the ANEEL Ratifying Resolution nº 1667/2013 [ANEEL, 2015].

*medium* and *low* water flow years, the GSF is equal to 1.00 and 0.75, respectively. This means that the four generators together produce either 100% (medium) or only 75% (low) of their physical guarantees. Besides that, as typically more than 85% of the demand in Brazil is supplied by hydro generation, the variable $Q_h$ embodies this figure.

**Table 5.2 – Demand and dispatch data throughout the year (MWaverage or $/MWaverage)**

| | ***Month*** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $Q_{total}$ | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 | 500 |
| | $PLD_{nh}$ | 217 | 117 | 117 | 57 | 57 | 57 | 117 | 117 | 317 | 417 | 517 | 617 |
| High water flow | $Q_{nh}$ | 167 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| | $Q_h$ | 333 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 |
| | $NAE_{total}$ | 333 | 666 | 1,166 | 1,833 | 1,666 | 833 | 666 | 167 | 167 | 0 | 0 | 0 |
| Medium water flow | $Q_{nh}$ | 250 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 250 |
| | $Q_h$ | 250 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 495 | 250 |
| | $NAE_{total}$ | 267 | 533 | 933 | 1,466 | 1,333 | 667 | 533 | 133 | 133 | 0 | 0 | 0 |
| Low water flow | $Q_{nh}$ | 300 | 100 | 5 | 5 | 5 | 5 | 5 | 5 | 200 | 300 | 300 | 300 |
| | $Q_h$ | 200 | 400 | 495 | 495 | 495 | 495 | 495 | 495 | 300 | 200 | 200 | 200 |
| | $NAE_{total}$ | 200 | 400 | 700 | 1,100 | 1,000 | 500 | 400 | 100 | 100 | 0 | 0 | 0 |

The next sections focus on BID1 (Section 5.1.1) and BID2 (Section 5.1.2). Section 5.1.3 discusses whether the algorithm fulfills its intended purpose.

### 5.1.1 Concerning BID1

To start with, the simulations consider all the aforementioned water flows patterns, market conditions and seasonalization for the "$PLD_{nh}$" ceiling price rule. Table 5.3 details the 18 scenarios and shows the optimal bidding obtained for each hydro.

**Table 5.3 – BID1: optimal bidding strategy for all hydros, scenarios and states**

| **Scenarios** | | | | **Best action policy** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Water flow** | **Seaso** | **qCE level** | **no.** | ***State s1*** | | | | ***State s2*** | | | | ***State s3*** | | | |
| | | | | *Hydro* | | | | *Hydro* | | | | *Hydro* | | | |
| | | | | 1 | *2* | *3* | *4* | 1 | *2* | *3* | *4* | 1 | *2* | *3* | *4* |
| *high* | *FLAT* | 100% | 1 | a12 | a12 | a12 | a12 | a3 | a3 | a5 | a6 | - | - | - | - |
| | | 50% | 2 | a12 | a12 | a12 | a12 | a6 | a7 | a6 | a6 | - | - | - | - |
| | | 0% | 3 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |
| | *NAE* | 100% | 4 | a12 | a12 | a12 | a12 | - | - | - | - | a1 | a1 | a1 | a1 |
| | | 50% | 5 | a12 | a12 | a12 | a12 | - | - | - | - | a1 | a1 | a1 | a1 |
| | | 0% | 6 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |
| *medium* | *FLAT* | 100% | 7 | a12 | a12 | a12 | a12 | a3 | a5 | a4 | a4 | - | - | - | - |
| | | 50% | 8 | a12 | a12 | a12 | a12 | a5 | a3 | a3 | a3 | - | - | - | - |
| | | 0% | 9 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |
| | *NAE* | 100% | 10 | a12 | a12 | a12 | a12 | a7 | a7 | a3 | a3 | a1 | a1 | a1 | a1 |
| | | 50% | 11 | a12 | a12 | a12 | a12 | - | - | - | - | a1 | a1 | a1 | a1 |
| | | 0% | 12 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |
| *low* | *FLAT* | 100% | 13 | a12 | a12 | a12 | a12 | a7 | a7 | a7 | a7 | - | - | - | - |
| | | 50% | 14 | a12 | a12 | a12 | a12 | a4 | a7 | a4 | a3 | - | - | - | - |
| | | 0% | 15 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |
| | *NAE* | 100% | 16 | a12 | a12 | a12 | a12 | a7 | a7 | a7 | a4 | a1 | a1 | a1 | a1 |
| | | 50% | 17 | a12 | a12 | a12 | a12 | - | - | - | - | a1 | a1 | a1 | a1 |
| | | 0% | 18 | - | - | - | - | - | - | - | - | a1 | a1 | a1 | a1 |

The Q-learning for BID1 adopts a learning rate α equal to 0.9 and a discount factor γ equal to 0. It converges after simulating around 1,000 years and it considers a tolerance of 0.5% on the values of the Q-learning matrix built in a given iteration regarding the previous one. The states and actions mentioned in Table 5.3 follow the action and space concepts already presented in Table 4.2 (Section 4.5.1). In order to facilitate reading this information, Table 5.4 summarizes the best actions obtained in this simulation, in terms of pairs (qBID, pBID). The Simulating Annealing here adopts Temp equals to $10^{13}$ and $\Phi$ equals to 0.8.

**Table 5.4 – Best actions in terms of pair (qBID, pBID)**

| Action | qBID | pBID (% of PLDreg_uplim) |
|---|---|---|
| a1 | 0 | 0% |
| a3 | 100% . ERA | 100% |
| a4 | | 75% |
| a5 | | 50% |
| a6 | | 25% |
| a7 | | 0% |
| a12 | 100% . qCE | 0% |

*5.1.1.1 High water flow scenarios*

For scenarios no. 1 and 2 (where seasonalization is flat and there is a contract to be sustained, i.e. qCE > 0), ERA lower than qCE occurs (state s2) in the first month (mainly because ERA starts with balance zero) and in the driest months (i.e. those with lowest $NAE_{total}$). When this happens, obviously it is not possible to endure all energy committed by contracts because there is not enough energy available to do so. Nevertheless, the selected action adopts the strategy of using all the available energy in the account (ERA) to mitigate the punishment. Thus, actions from a3 to a7 are chosen instead of action a2 (qBID equal to zero and pBID equal to the ceiling price).

On the contrary, when ERA > qCE (state *s*1) it happens that the best action is always a12: to bid a quantity equal to qCE at zero price. The action a12 represents the best the agent can do to withstand the contract at its minimum risk (pBID equal to zero in order to really avoid negative exposition in the short-term market). Subsequently, state s3 (qCE = 0) happens when there is no contract to be sustained. In this case (scenario no. 3), the agent offers qBID1 equal to zero, saving all energy for BID2. In Table 5.5 it is possible to visualize for scenario no. 1 the best actions (after convergence) throughout the year for each of four hydros (action a12 is the only not hatched).

**Table 5.5 – Best actions throughout the year in scenario no. 1**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| H1 | a3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a3 | a3 |
| H2 | a3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a3 | a3 |
| H3 | a5 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a5 |
| H4 | a6 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a6 | a6 |

Now regarding *NAE_seaso* scenarios (no. 4, 5 and 6), no episode registered an ERA lower than qCE (state *s*2) even when hydros are entirely committed, i.e. their physical guarantee is 100% dedicated through bilateral contracts. In dry months, qCE can be zero (state *s*3 and action a1) in scenarios no. 4 and 5 since NAE is equal to zero and consequently the seasonalized qCE is also equal to zero. In *NAE_seaso* scenarios, when qCE is different from zero the best strategy is also to offer 100% of the qCE at a price equal to zero (action a12). For scenario no. 4, Table 5.6 presents the best actions throughout the year for all hydros (action a1 is lightly hatched).

**Table 5.6 – Best actions throughout the year in scenario no. 4**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
| H1 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H2 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H4 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |

Summing up, when state s1 occurs (ERA > qCE) the agent's choice is always a12. This action is selected instead of a2, a8, a9, a10, and a11 to avoid negative financial exposition. If there is an attempt to push the price closer to the ceiling price by choosing pBID higher than zero, owing to the competition in the short-term market, there will be a risk of not being dispatched. Thus, he cannot uphold the total ex-ante contracted amount. Among these scenarios, no. 4 is the one that better illustrates the flexibility to comply with contracts given that hydros are 100% committed. For this scenario, Figure 5.1 shows that qBIDs (dots) are always equal to qCE values given in the lines for all hydros (i = 1, 2, 3 and 4).

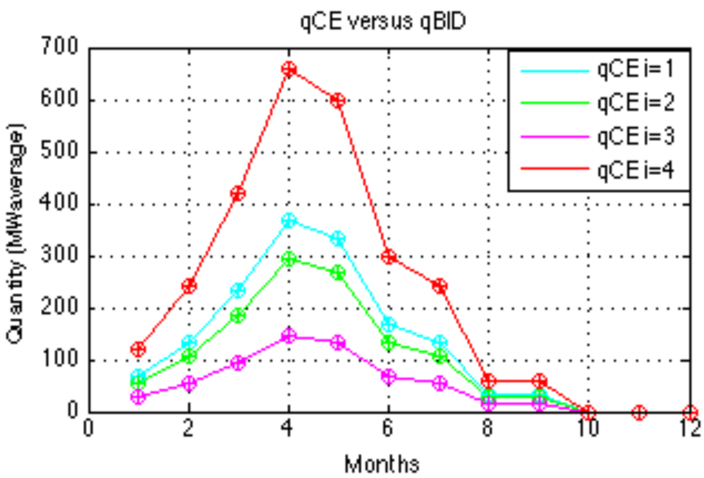


**Figure 5.1 – Quantity bids versus ex-ante contracts in scenario no. 4**

When in state s2 (ERA ≤ qCE), agents try to compensate the lack of energy to uphold their contracts by offering as much as possible at prices often close to the lowest levels. So, they choose from a3 to a7, instead of a2. As can be noticed, a2 would be a wrong choice: a qBID equal to zero completely exposes them to the obligation of having to buy electricity in the short-term market to fulfill their contracts. When state s1 (qCE = 0) occurs, there is no need to endure contracts. Thus, agents offer qBID and pBID equal to zero to save water for BID2.

*5.1.1.2 Medium water flow scenarios*

In the medium water scenarios (scenario no. 7 until 12) we also observe the same pattern for the bidding strategy of high water flow scenarios. However, some changes are noticed. In *FLAT_seaso* scenarios, given that water flows are more reduced compared with the corresponding previous scenarios, the best actions have large price bids more often. For instance, by comparing the occurrence of actions in scenario no. 2 (a6 and a7) with those from scenario no. 8 (a3 and a5) in dry months (months no. 10, 11 and 12), we can notice that as inflows begin to decrease hydros can have successful bids with higher pBID. This result is expected when resources become scarce.

Tables 5.7, 5.8 and 5.9 present the best actions for scenario no. 2, no. 8 and no. 10, respectively. As can be seen in Table 5.7 and Table 5.8 (hatched cells in end of the year), while in scenario no. 2 the best action is either a7 (pBID = 0) or a6 (pBID = 25%.PLDreg_uplim), in scenario no. 8 the action chosen is either a5 (pBID = 50%.PLDreg_uplim) or a3 (pBID = 75%.PLDreg_uplim).

**Table 5.7 – Best actions throughout the year in scenario no. 2**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| H1 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a6 | a6 |
| H2 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a7 |
| H3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a6 | a6 | a6 |
| H4 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a6 |

**Table 5.8 – Best actions throughout the year in scenario no. 8**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| H1 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a3 | a3 | a3 |
| H2 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a3 | a3 |
| H3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a5 | a5 | a5 | a5 |
| H4 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a3 |

Focusing on *NAE_seaso* scenarios, by analyzing scenarios no. 4 and no. 10 in Table 5.3 we can conclude that state *s*2 started to occur in scenario no. 10 because these are medium water flow scenarios. This means that, even adopting this type of seasonalization rule, there are months in which ERA ≤ qCE. This fact can also be observed by comparing Table 5.9 with Table 5.6. In Table 5.9 hydros face state s2 in the beginning of the year (so they choose a7 and a3). In Table 5.6, for the same period the action chosen is a12 (only available in state s1: ERA > qCE).

**Table 5.9 – Best actions throughout the year in scenario no. 10**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| H1 | a7 | a7 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H2 | a7 | a7 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H3 | a3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H4 | a3 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |

*5.1.1.3 Low water flow scenarios*

The incidence of state s2 (ERA ≤ qCE) in all *NAE_seaso* scenarios is higher when the worst hydrological year comes. When this happens, hydros have more difficulty to fully endure their contracts. Table 5.10 presents the best actions through the year for scenario no. 16, and it shows that hydros are facing state s2 (i.e. suffering water scarcity to comply contracts) for a longer period than in the previous scenarios (from month no. 1 to month no. 4). This fact becomes more evident with comparing the results of scenario no. 16 (Table 5.10) with its peers (*NAE_seaso* and qCE = 100%) from the other weather patterns (Table 5.9 and Table 5.4). Moreover, in low water flow scenarios hydros are more likely to choose actions with a lower pBID than other available actions in state s2. Indeed, they very often decide by a7, which is the action with the lowest pBID. Given that in a7 the pBID is equal to zero, this action increases the chances of hydros to be dispatched.

**Table 5.10 – Best actions throughout the year in scenario no. 16**

| Hydro | Month | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** | **11** | **12** |
| H1 | a7 | a7 | a7 | a7 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H2 | a7 | a7 | a7 | a7 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H3 | a7 | a7 | a7 | a7 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |
| H4 | a4 | a4 | a4 | a12 | a12 | a12 | a12 | a12 | a12 | a1 | a1 | a1 |

When there is water scarcity electricity prices strongly rise, which means that a negative exposed position is a very relevant issue: losses are greater when one has to fulfill his bilateral contract by buying energy at prices closer to the ceiling price. So, during these periods hydros really try to avoid this. In a market based on bids as the VRM, this can be done offering as much as possible at the lowest price, i.e. they choose a7 (qBID = 100%.ERA; pBID = 0).

Lastly, the worst scenario for the purpose of BID1 occurs when the hydrological year is bad, the seasonalization process is performed in flat mode, and hydros are fully committed through bilateral contracts (scenario no. 13). In this case, the best actions are: a12 for state *s*1 and a7 for state *s*2 (there are no events in state *s*3). Figure 5.2 presents the results for qCE (line) and qBID (dot). As it can be observed, qCE cannot be kept during all months by qBIDs because there is not enough energy available in the ERA in several periods along the year.

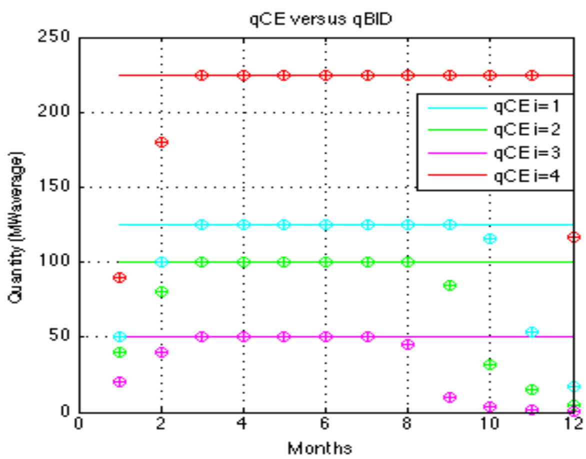


**Figure 5.2 – Quantity bids versus ex-ante contracts in scenario no. 13**

### 5.1.2 Concerning BID2

In the case of BID2, the simulations consider the same three weather patterns (*high*, *medium* and *low*) and levels of ex-ante contract (100%, 50% and 0%) of BID1. In addition, the two types of ceiling price rules are used (*$PLD_{nh}$* and *Fixed*), and the seasonalization of the bilateral contracts is only shaped according to the water inflow (*NAE_seaso* mode).

Giving these assumptions, 18 scenarios were tested and analyzed. The Q-learning mechanism used in the formulation of BID2 converges after simulating around 1,100 years (which takes about 1 minute to process it). The tolerance criterion is 5%. It was used a learning rate α and a discount factor γ equal to 0.9 and 1, respectively. The value adopted for γ is justified in order to stimulate the agents to strive for a long-term high reward as much as possible. The α is the same as for BID1 (0.9) in order to allow the agents to learn with the new information at the same proportion (90%). The Simulating Annealing for BID2 presents the parameters Temp and $\Phi$ equal to $10^{14}$ and 0.95, respectively.

Table 5.11 enumerates all the mentioned scenarios and presents the optimal bidding actions for each state, regarding Hydro 4 (the largest reservoir). In Table 5.12 and Table 5.13 each best action is then depicted in its corresponding quantity (qBID) and price bid (pBID), respectively.

**Table 5.11 – BID2: optimal bidding strategy of Hydro 4 in all scenarios and states**

| **Scenarios** | | | | *Hydro 4* | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Best action policy** | | | | | | | | | | | |
| | | | | ***States*** | | | | | | | | | | | |
| **Water flow** | ***Ceiling price rule*** | **qCE level** | **no.** | **1** | ***2*** | ***3*** | ***4*** | **5** | ***6*** | ***7*** | ***8*** | **9** | ***10*** | ***11*** | ***12*** |
| *high* | *$PLD_{nh}$* | 100% | 1 | a7 | a19 | a17 | a22 | a21 | a23 | a5 | a10 | a2 | a7 | a6 | a9 |
| | | 50% | 2 | a11 | a14 | a23 | a12 | a6 | a18 | a20 | a11 | a7 | a16 | a11 | a14 |
| | | 0% | 3 | a11 | a13 | a14 | a15 | a17 | a13 | a4 | a3 | a7 | a24 | a2 | a4 |
| | *Fixed* | 100% | 4 | a11 | a2 | a14 | a5 | a17 | a15 | a8 | a21 | a5 | a12 | a12 | a4 |
| | | 50% | 5 | a9 | a4 | a8 | a6 | a11 | a25 | a26 | a12 | a7 | a8 | a8 | a2 |
| | | 0% | 6 | a8 | a4 | a10 | a4 | a14 | a8 | a6 | a21 | a10 | a4 | a9 | a2 |
| *medium* | *$PLD_{nh}$* | 100% | 7 | a1 | a6 | a22 | a11 | a27 | a2 | a5 | a8 | a25 | a9 | a7 | a22 |
| | | 50% | 8 | a5 | a24 | a10 | a11 | a11 | a25 | a20 | a22 | a3 | a10 | a7 | a12 |
| | | 0% | 9 | a26 | a7 | a14 | a16 | a18 | a8 | a17 | a20 | a27 | a13 | a21 | a2 |
| | *Fixed* | 100% | 10 | a1 | a9 | a22 | a16 | a24 | a10 | a8 | a6 | a7 | a13 | a17 | a26 |
| | | 50% | 11 | a23 | a13 | a5 | a11 | a21 | a16 | a8 | a26 | a17 | a20 | a4 | a13 |
| | | 0% | 12 | a17 | a7 | a25 | a13 | a24 | a12 | a26 | a3 | a24 | a4 | a12 | a9 |
| *low* | *$PLD_{nh}$* | 100% | 13 | a1 | a1 | a1 | a1 | a2 | a13 | a10 | a13 | a10 | a6 | a12 | a10 |
| | | 50% | 14 | a25 | a9 | a18 | a7 | a24 | a8 | a14 | a4 | a22 | a7 | a12 | a12 |
| | | 0% | 15 | a10 | a21 | a25 | a13 | a15 | a15 | a19 | a2 | a25 | a2 | a2 | a2 |
| | *Fixed* | 100% | 16 | a1 | a1 | a1 | a1 | a25 | a25 | a4 | a21 | a14 | a16 | a17 | a23 |
| | | 50% | 17 | a24 | a21 | a16 | a16 | a22 | a17 | a21 | a17 | a10 | a7 | a5 | a25 |
| | | 0% | 18 | a18 | a16 | a16 | a15 | a21 | a8 | a6 | a12 | a6 | a7 | a6 | a2 |

**Table 5.12 – BID2: optimal qBIDs for Hydro 4**

| Scenarios | | | | *Hydro 4* | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Best action policy: qBID** | | | | | | | | | | | |
| **Water flow** | ***Ceiling price rule*** | **qCE level** | **no.** | ***States*** | | | | | | | | | | | |
| | | | | **1** | ***2*** | ***3*** | ***4*** | **5** | ***6*** | ***7*** | ***8*** | **9** | ***10*** | ***11*** | ***12*** |
| *high* | *$PLD_{nh}$* | 100% | 1 | 20 | 80 | 60 | 80 | 80 | 100 | 20 | 40 | 0 | 20 | 20 | 40 |
| | | 50% | 2 | 40 | 60 | 100 | 40 | 20 | 80 | 80 | 40 | 20 | 60 | 40 | 60 |
| | | 0% | 3 | 40 | 40 | 20 | 20 | 40 | 80 | 60 | 20 | 0 | 60 | 40 | 60 |
| | *Fixed* | 100% | 4 | 40 | 0 | 60 | 20 | 60 | 60 | 40 | 80 | 20 | 40 | 40 | 20 |
| | | 50% | 5 | 40 | 20 | 40 | 20 | 40 | 100 | 100 | 40 | 20 | 40 | 40 | 0 |
| | | 0% | 6 | 40 | 20 | 40 | 20 | 60 | 40 | 20 | 80 | 40 | 20 | 40 | 0 |
| *medium* | *$PLD_{nh}$* | 100% | 7 | 0 | 20 | 80 | 40 | 100 | 0 | 20 | 40 | 100 | 40 | 20 | 80 |
| | | 50% | 8 | 20 | 100 | 40 | 40 | 40 | 100 | 80 | 80 | 20 | 40 | 20 | 40 |
| | | 0% | 9 | 100 | 20 | 60 | 60 | 80 | 40 | 60 | 80 | 100 | 60 | 80 | 0 |
| | *Fixed* | 100% | 10 | 0 | 40 | 80 | 60 | 100 | 40 | 40 | 20 | 20 | 60 | 60 | 100 |
| | | 50% | 11 | 100 | 60 | 20 | 40 | 80 | 60 | 40 | 100 | 60 | 80 | 20 | 60 |
| | | 0% | 12 | 60 | 20 | 100 | 60 | 100 | 40 | 100 | 20 | 100 | 20 | 40 | 40 |
| *low* | *$PLD_{nh}$* | 100% | 13 | 0 | 0 | 0 | 0 | 0 | 60 | 40 | 60 | 40 | 20 | 40 | 40 |
| | | 50% | 14 | 100 | 40 | 80 | 20 | 100 | 40 | 60 | 20 | 80 | 20 | 40 | 40 |
| | | 0% | 15 | 40 | 80 | 100 | 60 | 60 | 60 | 80 | 0 | 100 | 0 | 0 | 0 |
| | *Fixed* | 100% | 16 | 0 | 0 | 0 | 0 | 100 | 100 | 20 | 80 | 60 | 60 | 60 | 100 |
| | | 50% | 17 | 100 | 80 | 60 | 60 | 80 | 60 | 80 | 60 | 40 | 20 | 20 | 100 |
| | | 0% | 18 | 80 | 60 | 60 | 60 | 80 | 40 | 20 | 40 | 20 | 20 | 20 | 0 |

**Table 5.13 – BID2: optimal pBIDs for Hydro 4**

| Scenarios | | | | *Hydro 4* | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Best action policy: pBID** | | | | | | | | | | | |
| **Water flow** | ***Ceiling price rule*** | **qCE level** | **no.** | ***States*** | | | | | | | | | | | |
| | | | | **1** | ***2*** | ***3*** | ***4*** | **5** | ***6*** | ***7*** | ***8*** | **9** | ***10*** | ***11*** | ***12*** |
| *high* | *$PLD_{nh}$* | 100% | 1 | 100 | 25 | 100 | 100 | 75 | 0 | 50 | 50 | 100 | 100 | 75 | 25 |
| | | 50% | 2 | 75 | 25 | 0 | 100 | 75 | 0 | 50 | 75 | 100 | 75 | 75 | 25 |
| | | 0% | 3 | 25 | 0 | 75 | 50 | 75 | 50 | 100 | 100 | 100 | 75 | 75 | 100 |
| | *Fixed* | 100% | 4 | 75 | 100 | 25 | 50 | 100 | 50 | 0 | 75 | 50 | 100 | 100 | 25 |
| | | 50% | 5 | 25 | 25 | 0 | 75 | 75 | 50 | 75 | 100 | 100 | 0 | 0 | 100 |
| | | 0% | 6 | 0 | 25 | 50 | 25 | 25 | 0 | 75 | 75 | 50 | 25 | 25 | 100 |
| *medium* | *$PLD_{nh}$* | 100% | 7 | 0 | 75 | 100 | 75 | 100 | 100 | 50 | 0 | 50 | 25 | 100 | 100 |
| | | 50% | 8 | 50 | 25 | 50 | 75 | 75 | 50 | 50 | 100 | 0 | 50 | 100 | 100 |
| | | 0% | 9 | 75 | 100 | 25 | 75 | 0 | 0 | 100 | 50 | 100 | 0 | 75 | 100 |
| | *Fixed* | 100% | 10 | 0 | 25 | 100 | 75 | 25 | 50 | 0 | 75 | 100 | 0 | 100 | 75 |
| | | 50% | 11 | 0 | 0 | 50 | 75 | 75 | 75 | 0 | 75 | 100 | 50 | 25 | 0 |
| | | 0% | 12 | 100 | 100 | 50 | 0 | 25 | 100 | 75 | 0 | 25 | 25 | 100 | 25 |
| *low* | *$PLD_{nh}$* | 100% | 13 | 0 | 0 | 0 | 0 | 100 | 0 | 50 | 0 | 50 | 75 | 100 | 50 |
| | | 50% | 14 | 50 | 25 | 0 | 100 | 25 | 0 | 25 | 25 | 100 | 100 | 100 | 100 |
| | | 0% | 15 | 50 | 75 | 50 | 0 | 50 | 50 | 25 | 100 | 50 | 100 | 100 | 100 |
| | *Fixed* | 100% | 16 | 0 | 0 | 0 | 0 | 50 | 50 | 25 | 75 | 25 | 75 | 100 | 0 |
| | | 50% | 17 | 25 | 75 | 75 | 75 | 100 | 100 | 75 | 100 | 50 | 100 | 50 | 50 |
| | | 0% | 18 | 0 | 75 | 75 | 50 | 75 | 0 | 75 | 100 | 75 | 100 | 75 | 100 |

As it can be observed, in the case of BID2 the interpretation of the optimal bidding strategy is not trivial. Even after disaggregating the actions described in Table 5.11 in two components

(Tables 5.12 and 5.13) there is not a clear picture. In order to turn this interpretation easier, Table 5.14 shows the results regarding the $factor_{goal\_t}$ of Hydro 4. As discussed in Section 4.5.2, the $factor_{goal\_t}$ reflects the achievement of reservoir's target levels. So, through Table 5.14 it is possible to analyze the behavior of Hydro 4 in relation to the hydro's target.

**Table 5.14 – BID2: $Factor_{goal\_t}$ of Hydro 4 sorted according to the qCE value**

| | Scenarios | | | | $Factor_{goal\_t}$ | | | | | | | | | | | | $PLDh_{average}$ ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Water flow** | ***Ceiling price rule*** | **qCE level** | **no.** | *State* 1 | *2* | *3* | *4* | 5 | *6* | *7* | *8* | 9 | *10* | *11* | *12* | |
| *group 1* | *High* | $PLD_{nh}$ | 100% | 1 | 1 | 1 | 0,4 | 0 | 0,4 | 0,7 | 0,7 | 0,7 | 1 | 1 | 0,7 | 0,7 | **155** |
| | *Medium* | | | 7 | 1 | 1 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,7 | 0,9 | 0,9 | 1 | **165** |
| | *Low* | | | 13 | 1 | 0,9 | 0,9 | 0,7 | 0 | 0 | 0 | 0,7 | 0,7 | 0,9 | 0,9 | 0,9 | **174** |
| *group 2* | *High* | *Fixed* | | 4 | 1 | 0,9 | 0,4 | 0 | 0,4 | 0,7 | 0,7 | 0,4 | 0,7 | 1 | 0,9 | 0,9 | **310** |
| | *Medium* | | | 10 | 1 | 1 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0 | 0,4 | 0,9 | 1 | **310** |
| | *Low* | | | 16 | 1 | 0,9 | 0,7 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,4 | 0,9 | 1 | **379** |
| *group 3* | *High* | $PLD_{nh}$ | 50% | 2 | 1 | 1 | 0,7 | 0,4 | 0,7 | 1 | 1 | 1 | 1 | 0,7 | 0,7 | 0,7 | **163** |
| | *Medium* | | | 8 | 1 | 0,9 | 1 | 0,4 | 0,9 | 1 | 0,9 | 0 | 0,4 | 0,4 | 0,7 | 0,7 | **181** |
| | *Low* | | | 14 | 1 | 1 | 1 | 0,9 | 0,7 | 1 | 0,7 | 0,4 | 0,4 | 0,4 | 0 | 0,9 | **178** |
| *group 4* | *High* | *Fixed* | | 5 | 1 | 0,9 | 0,4 | 0,4 | 0,7 | 0,7 | 1 | 1 | 1 | 0,9 | 0,9 | 1 | **379** |
| | *Medium* | | | 11 | 1 | 1 | 0,9 | 0,4 | 0,9 | 0,7 | 0,9 | 0,7 | 0,4 | 0 | 0,4 | 0,7 | **431** |
| | *Low* | | | 17 | 1 | 1 | 1 | 0,9 | 0,4 | 0,4 | 0,4 | 0,9 | 0,9 | 1 | 1 | 0,9 | **517** |
| *group 5* | *High* | $PLD_{nh}$ | 0% | 3 | 0,9 | 0,9 | 0,4 | 0 | 0 | 0,7 | 0,7 | 0,4 | 0 | 0 | 0 | 0,7 | **176** |
| | *Medium* | | | 9 | 1 | 0,9 | 0,4 | 0 | 0,7 | 0,9 | 0,4 | 0 | 0 | 0 | 0 | 0,7 | **184** |
| | *Low* | | | 15 | 0,9 | 1 | 1 | 0,9 | 0,9 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,7 | **181** |
| *group 6* | *High* | *Fixed* | | 6 | 1 | 0,7 | 0 | 0 | 0 | 0,9 | 0,9 | 0,7 | 0,4 | 0,4 | 0,4 | 0,9 | **516** |
| | *Medium* | | | 12 | 1 | 0,7 | 0,7 | 0 | 0 | 0,4 | 0,9 | 0,9 | 0,4 | 0,4 | 0,4 | 0,7 | **586** |
| | *Low* | | | 18 | 1 | 1 | 1 | 0 | 0,9 | 0,9 | 0,9 | 0,9 | 0,9 | 0,9 | 1 | 0,9 | **638** |

Table 5.14 doesn't present the scenarios in an ascendant order (unlike Table 5.11). This is because in this way it is easier to note that the level of contract (qCE equal to 100%, 50% and 0%) plays a very important role in shaping the results. For instance, it seems that the groups formed by the same level of qCE (i.e. group 1: scenarios no. 1, 7 and 13; group 2: scenarios no. 4, 10, 16; group 3: scenarios no. 2, 8, 14; group 4: scenarios no. 5, 11, 17; group 5: scenarios no. 3, 9, 15; group 6: scenarios no. 6, 12, 18) have a certain kind of regularities in their results.

In groups 1 and 2 (qCE equal to 100%), for the *Medium* and *Low* scenarios and around the second and third trimester of the year, the hydro doesn't come close to achieve its target ($factor_{goal\_t}$ equal to 0). In groups 3 and 4 (qCE equal to 50%), the hydro has been close to his target almost all the time ($factor_{goal\_t}$ equal to 0 just in a few months). In groups 5 and 6 (qCE equal to 0%) the $factor_{goal\_t}$ is equal to 0 during part of the second trimester. In addition, in group 5 ($PLD_{nh}$), in the second semester of the year, the hydro ends up far way from his target ($factor_{goal\_t}$ equal to 0), and this is worse when the water inflow scenario goes from the *High* to the *Low* one.

In Table 5.15 these results are presented sorted taking into account the groups and the value of the annual $PLD_{average}$. As it can be observed, the price increases from the *High* to the *Low* scenarios, from the *PLDnh* ceiling price rule to the *Fixed* one, and from the level of bilateral contract equal to 100% to 0%.

**Table 5.15 – BID2: $Factor_{goal\_t}$ of Hydro 4 sorted by the annual $PLD_{average}$**

| | Scenarios | | | | $Factor_{goal\_t}$ | | | | | | | | | | | | $PLDh_{average}$ ($/MWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Water flow** | ***Ceiling price rule*** | **qCE level** | **no.** | *State* | | | | | | | | | | | | |
| | | | | | 1 | *2* | *3* | *4* | 5 | *6* | *7* | *8* | 9 | *10* | *11* | *12* | |
| *group 1* | *High* | $PLD_{nh}$ | 100% | 1 | 1 | 1 | 0,4 | 0 | 0,4 | 0,7 | 0,7 | 0,7 | 1 | 1 | 0,7 | 0,7 | **155** |
| | *Medium* | | | 7 | 1 | 1 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,7 | 0,9 | 0,9 | 1 | **165** |
| | *Low* | | | 13 | 1 | 0,9 | 0,9 | 0,7 | 0 | 0 | 0 | 0,7 | 0,7 | 0,9 | 0,9 | 0,9 | **174** |
| *group 3* | *High* | | 50% | 2 | 1 | 1 | 0,7 | 0,4 | 0,7 | 1 | 1 | 1 | 1 | 0,7 | 0,7 | 0,7 | **163** |
| | *Medium* | | | 8 | 1 | 0,9 | 1 | 0,4 | 0,9 | 1 | 0,9 | 0 | 0,4 | 0,4 | 0,7 | 0,7 | **181** |
| | *Low* | | | 14 | 1 | 1 | 1 | 0,9 | 0,7 | 1 | 0,7 | 0,4 | 0,4 | 0,4 | 0 | 0,9 | **178** |
| *group 5* | *High* | | 0% | 3 | 0,9 | 0,9 | 0,4 | 0 | 0 | 0,7 | 0,7 | 0,4 | 0 | 0 | 0 | 0,7 | **176** |
| | *Medium* | | | 9 | 1 | 0,9 | 0,4 | 0 | 0,7 | 0,9 | 0,4 | 0 | 0 | 0 | 0 | 0,7 | **184** |
| | *Low* | | | 15 | 0,9 | 1 | 1 | 0,9 | 0,9 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,7 | **181** |
| *group 2* | *High* | *Fixed* | 100% | 4 | 1 | 0,9 | 0,4 | 0 | 0,4 | 0,7 | 0,7 | 0,4 | 0,7 | 1 | 0,9 | 0,9 | **310** |
| | *Medium* | | | 10 | 1 | 1 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0 | 0,4 | 0,9 | 1 | **310** |
| | *Low* | | | 16 | 1 | 0,9 | 0,7 | 0,7 | 0 | 0 | 0 | 0 | 0 | 0,4 | 0,9 | 1 | **345** |
| *group 4* | *High* | | 50% | 5 | 1 | 0,9 | 0,4 | 0,4 | 0,7 | 0,7 | 1 | 1 | 1 | 0,9 | 0,9 | 1 | **379** |
| | *Medium* | | | 11 | 1 | 1 | 0,9 | 0,4 | 0,9 | 0,7 | 0,9 | 0,7 | 0,4 | 0 | 0,4 | 0,7 | **431** |
| | *Low* | | | 17 | 1 | 1 | 1 | 0,9 | 0,4 | 0,4 | 0,4 | 0,9 | 0,9 | 1 | 1 | 0,9 | **517** |
| *group 6* | *High* | | 0% | 6 | 1 | 0,7 | 0 | 0 | 0 | 0,9 | 0,9 | 0,7 | 0,4 | 0,4 | 0,4 | 0,9 | **516** |
| | *Medium* | | | 12 | 1 | 0,7 | 0,7 | 0 | 0 | 0,4 | 0,9 | 0,9 | 0,4 | 0,4 | 0,4 | 0,7 | **586** |
| | *Low* | | | 18 | 1 | 1 | 1 | 0 | 0,9 | 0,9 | 0,9 | 0,9 | 0,9 | 0,9 | 1 | 0,9 | **638** |

The next two sections analyze the behavior focusing on two issues, quantity bid and price bid.

*5.1.2.1 Quantity bid behavior*

The linear programming problem embedded in the algorithm to establish the reservoir's target levels considers the monthly deposit ($DEP_t$), which reflects the weather condition. When solving this problem, agents are free to define their $qBID1'_t$ (or $qBID1\_goal_t$) and $qBID2'_t$ (or $qBID2\_goal_t$). The value of $qBID1\_goal_t$ is defined to be as close as possible to $qCE_t$, and $qBID2\_goal_t$ is formulated to optimize the leftover energy. This is done because, in the objective function, $qBID1\_goal_t$ has a greater weight (value of A, given by equation 4.14) than $qBID2\_goal_t$ ($PLDreg\_uplim_t$ in equation 4.13), forcing $qBID1\_goal_t$ to have precedence over $qBID2\_goal_t$.

To illustrate the results, Figures 5.3 and 5.4 show, for scenario no. 1 (high water inflow, $PLD_{nh}$ ceiling price rule, and qCE level equals to 100%) and no.3 (high water inflow, $PLD_{nh}$ ceiling price rule, and qCE level equals to 0%) the resulting targets (reservoir level, qBID1 and qBID2) from the linear programming output, the monthly deposits, and the actual reservoir levels and successful qBID1s and qBID2s. All qBIDs are represented in the graphs as a percentual of the reservoir capacity (RC). Bearing in mind that competition is not considered, the optimization (dashed green line) guides the agent to:

- keep the reservoir at low levels in the initial months until month 3, in scenario no. 1, and month 4, in scenario no. 3;
- sharply increase the level of the reservoir until the middle of the year, reaching its maximum level in month 7, in scenario no. 1, and month 9, in scenario no. 3; and
- in month 12decrease the reservoir level until it reaches its target of 25%. Nevertheless, in scenario no. 1 it happens gradually over the last semester of the year, and in scenario no. 3 it radically occurs with only one bid in the last month of the year.

In scenario no. 1, regarding the reservoir level, the shape of the actual curve is similar to the shape of the target one. Nevertheless, some difference can be noticed. In the first semester (period with the highest water inflow, as can be seen in the DEP curve) there are successful qBID1 (qBID1suc_atual) lower than the need to sustain contracts (qCE). However, this difference is offset by qBID2 in the second semester, where it is observed a qBID2suc_actual higher than qBID2_goal.

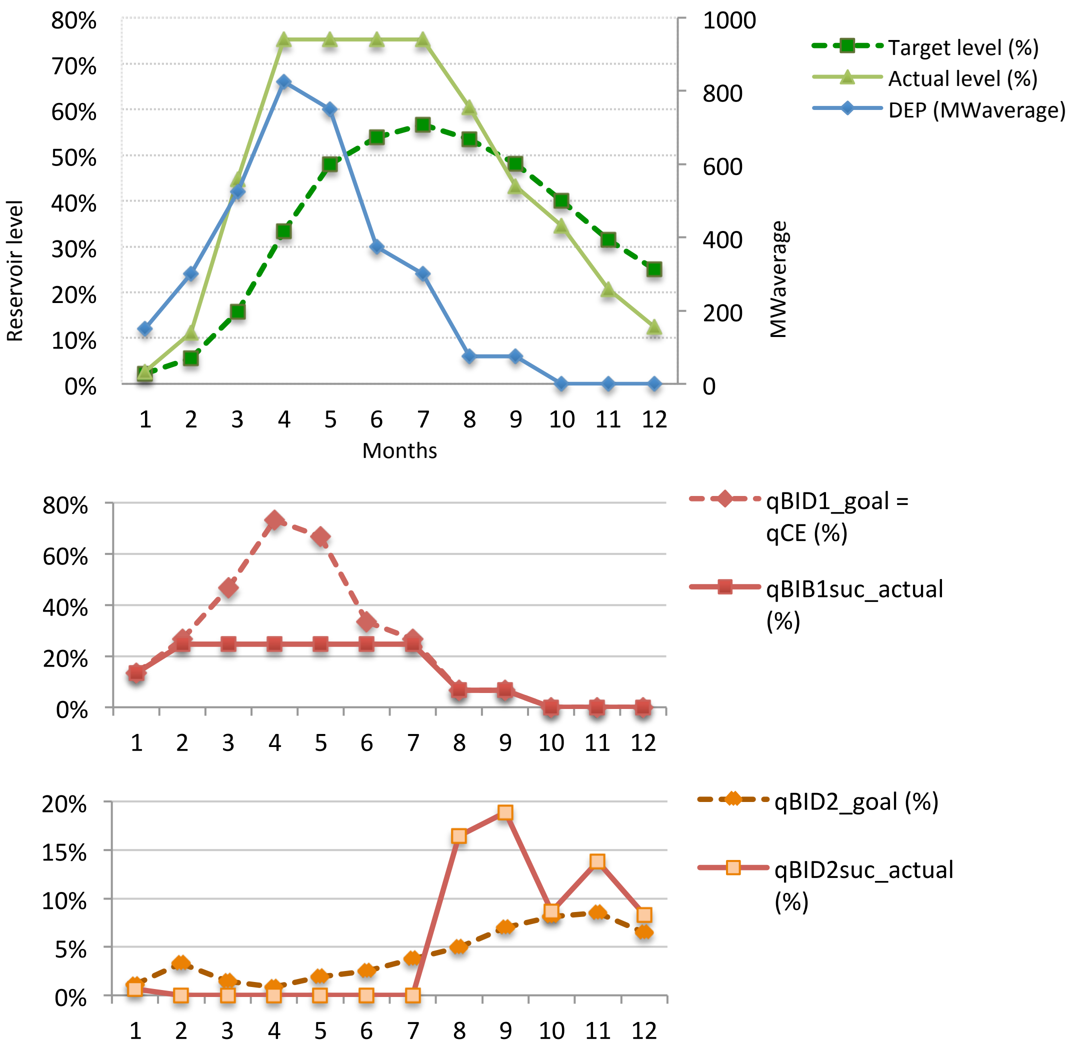


**Figure 5.3 – Data from hydro 4 in scenario no. 1**

In scenario no. 3 (qCE equal to zero and, therefore, qBID1_goal also equal to zero), there is a tendency of the actual reservoir level to follow its target levels. Yet, two events occur. In the beginning of the year, again during the period with the highest water inflow, there are successful qBID2 lower than its target. And again this is further offset by qBID2suc higher than qBID2_goal.

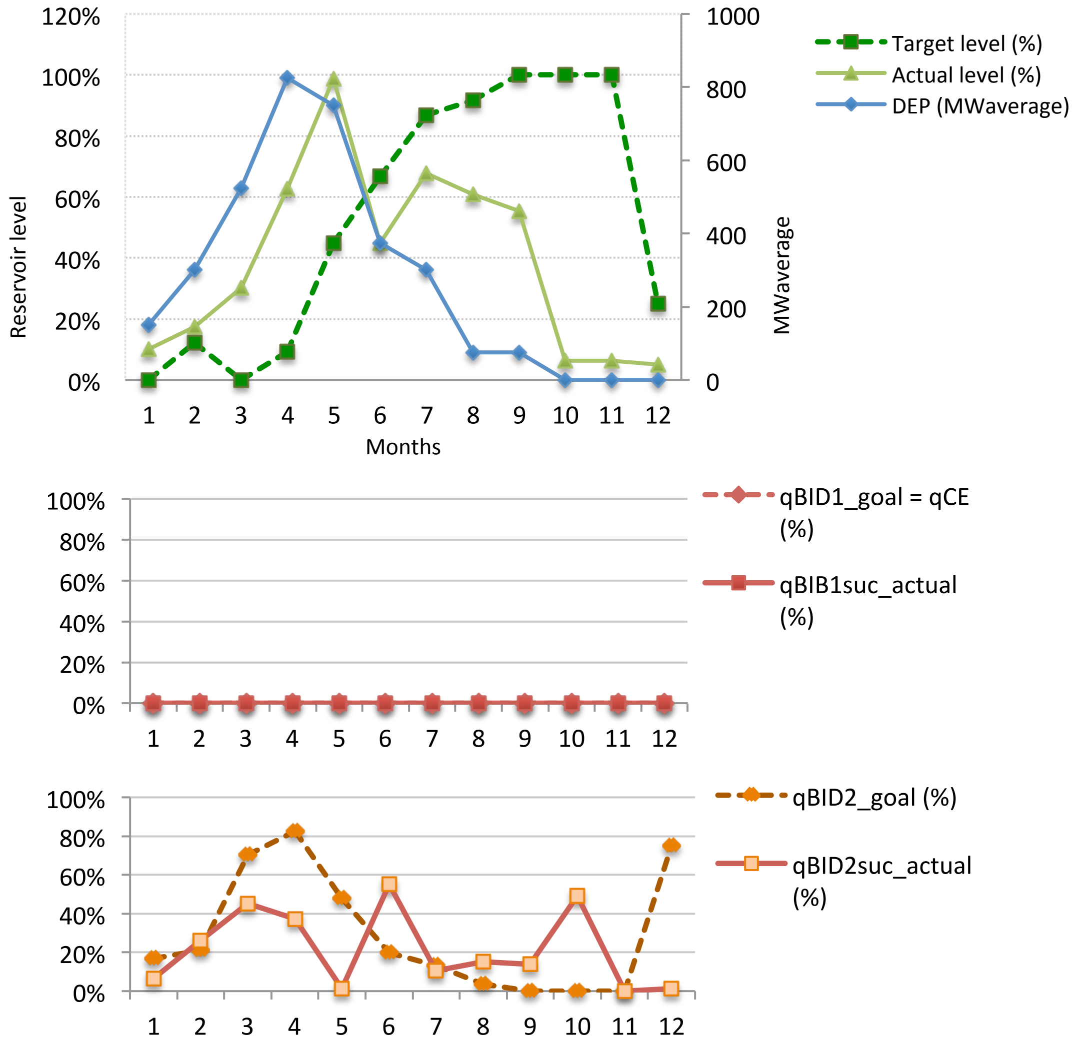


**Figure 5.4 – Data from hydro 4 in scenario no. 3**

The gap between the successful bids and its target in both scenarios happens because all the agents operate over the same goal-oriented scheme, which causes a generalized overbid in certain periods. So:

- In the beginning of the learning process all hydros tend to offer high amounts in the initial months of the year. By realizing the signal sent by the $factor_{goal\_t}$ (they perceive this through the reward calculated by equation 4.12), in the first rounds of the interaction hydros aim to get rid of the water; so competition grows. Once there is competition, bid quantities are larger than the total demand in this month, leading to partial non-accepted bids;

- To make up for it, hydros offer some high qBIDs in the upcoming months. In essence, at this stage of the learning process agents adapt to competition and improve their behavior offering more than previously planned.

In order to allow a closer look on the hydro's data, Table 5.15 is presented. Concerning Hydro 4 in scenario no. 1, this table shows the monthly updates of the ERA during the entire year, as well as the target and actual levels of the reservoir in the end of each month. This table also shows the virtual spillages (VS) of Hydro 4, the total demand into the hydro short-term market ($Q_h$), the quantity bids (qBIDs) offered by this hydro, his successful quantity bid target (qBIDsuc – target) and his actual successful quantity bid (qBIDsuc – actual), not only regarding BID2 but also BID1. These values were all obtained after the convergence of the algorithm.

**Table 5.16 – Hydro 4 in scenario no. 1: an overview of the monthly data**

<table>
<tr><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th></th><th colspan="2">qBID1suc</th><th></th><th colspan="2">qBID2suc</th><th colspan="2">Reservoir</th><th></th></tr>
<tr><th>Month</th><th>$ERA_{start}$</th><th>DEP</th><th>$ERA_{adep}$</th><th>VS</th><th>$ERA_{aspill}$</th><th>$Q_h$</th><th>qBID1</th><th>goal</th><th>actual</th><th>qBID2</th><th>goal</th><th>actual</th><th>goal</th><th>actual</th><th>$factor_{goal}$</th></tr>
<tr><td>1</td><td>0</td><td>150</td><td>150</td><td>0</td><td>150</td><td>333</td><td>120</td><td>120</td><td>120</td><td>6</td><td>10</td><td>6</td><td>2%</td><td>3%</td><td>1</td></tr>
<tr><td>2</td><td>24</td><td>300</td><td>324</td><td>0</td><td>324</td><td>495</td><td>240</td><td>240</td><td>223</td><td>0</td><td>29</td><td>0</td><td>6%</td><td>11%</td><td>1</td></tr>
<tr><td>3</td><td>101</td><td>**525**</td><td>**626**</td><td>0</td><td>626</td><td>495</td><td>420</td><td>420</td><td>223</td><td>123</td><td>13</td><td>0</td><td>**16%**</td><td>**45%**</td><td>**0,4**</td></tr>
<tr><td>4</td><td>403</td><td>**825**</td><td>**1228**</td><td>**328**</td><td>**900**</td><td>495</td><td>660</td><td>660</td><td>223</td><td>192</td><td>8</td><td>0</td><td>**33%**</td><td>**75%**</td><td>**0**</td></tr>
<tr><td>5</td><td>677</td><td>**750**</td><td>**1427**</td><td>**527**</td><td>**900**</td><td>495</td><td>600</td><td>600</td><td>223</td><td>180</td><td>17</td><td>0</td><td>**48%**</td><td>**75%**</td><td>**0,4**</td></tr>
<tr><td>6</td><td>677</td><td>**375**</td><td>**1052**</td><td>**152**</td><td>**900**</td><td>495</td><td>300</td><td>300</td><td>223</td><td>600</td><td>23</td><td>0</td><td>54%</td><td>75%</td><td>0,7</td></tr>
<tr><td>7</td><td>677</td><td>300</td><td>977</td><td>77</td><td>900</td><td>495</td><td>240</td><td>240</td><td>223</td><td>264</td><td>34</td><td>0</td><td>57%</td><td>75%</td><td>0,7</td></tr>
<tr><td>8</td><td>677</td><td>75</td><td>752</td><td>0</td><td>752</td><td>495</td><td>60</td><td>60</td><td>60</td><td>692</td><td>44</td><td>148</td><td>53%</td><td>60%</td><td>0,7</td></tr>
<tr><td>9</td><td>544</td><td>75</td><td>619</td><td>0</td><td>619</td><td>495</td><td>60</td><td>60</td><td>60</td><td>559</td><td>63</td><td>170</td><td>48%</td><td>43%</td><td>1</td></tr>
<tr><td>10</td><td>389</td><td>0</td><td>389</td><td>0</td><td>389</td><td>495</td><td>0</td><td>0</td><td>0</td><td>78</td><td>73</td><td>78</td><td>40%</td><td>35%</td><td>1</td></tr>
<tr><td>11</td><td>311</td><td>0</td><td>311</td><td>0</td><td>311</td><td>495</td><td>0</td><td>0</td><td>0</td><td>124</td><td>76</td><td>124</td><td>31%</td><td>21%</td><td>0,7</td></tr>
<tr><td>12</td><td>187</td><td>0</td><td>187</td><td>0</td><td>187</td><td>495</td><td>0</td><td>0</td><td>0</td><td>75</td><td>58</td><td>75</td><td>25%</td><td>12%</td><td>0,7</td></tr>
</table>

The results presented in Table 5.15 suggest the following observations:

- BID1: First and as explained in the previous section, we can note that all offered quantity BID1 (qBID1) coincides with its target (qBIDsuc – goal). Nevertheless, as highlighted by the cells shaded in light gray, in certain periods these values are different from the successful quantity bid (qBID1suc – actual). This is mainly because, due the seasonalization process of the hydros' contracts (type *NAE*, which means that the annual energy is monthly distributed according to the NAE profile), there are months where there is more contracted energy than total demand ($Q_h$). For example, in month 4, Qh is equal to 495 MWaverage and qBID1 (and its target) is equal to 660 MWaverage. Still, hydros have learned to offer the correct amount of BID1 in order to comply with their contracts;
- VS: The virtual spillage happens in months 4, 5 and 6, and this is because these periods are characterized by very high water flows, and this problem is intensified in the high water flow scenarios. As emphasized in the table (cells shaded in light gray with text in

bold), during these months it occurs the peak of water flow, and then ERAaspill reaches its maximum, i.e. the Reservoir Capacity (RC = 900 MWaverage);

- BID2: As earlier discussed, regarding BID2 hydros try to decrease their reservoir in the beginning of the year by offering substantial qBID2s. By doing so, they are striving to avoid the virtual spillages of the months 4, 5 and 6. However, there are more offers than the total demand and qBID2s are unsuccessful (cells shaded in dark gray – months 2 until 7). Hydro 4 will just have consistent successes close to the end of the year (months 8, 9, 10, 11 and 12), when the water flow decreases;
- Reservoir level: Both BID1 and BID2, if accepted, influence the reservoir level in the end of the month. Nonetheless, BID1 is designed only to endure the ex-ante contracts. And even considering certain issues (such as the type of seasonalization, high water flows in certain months, limitation coming from the reservoir capacity, periods where competitors try to sell a large amount of energy for a relatively small demand), the monthly reservoir levels is only away from its target in months 3, 4 and 5 (cells shaded in dark gray with text in bold). During the rest of the year it is possible to remain quite close to the target.

In addition, it should also be mentioned that, when there are more than one successful quantity bid (qBIDsuc) related with a price bid (pBIDsuc) equal to the clearing price, the algorithm includes a rule to proportionally decrease each of these qBIDsuc until all demand is covered. And during this process, in case of having both BID1 and BID2 with pBIDsuc equal to the clearing price, this procedure is applied only on BID2. This was designed to give BID1 priority over BID2, and thus to avoid partially unsuccessful BID1s, which would bring on involuntary exposed positions.

To sum up, we observe that, while the target coming from the linear programming problem suggests the agent reaches the reservoir level target at the end of each month, the Q-learning algorithm teaches the agent how to, at the same time, follow the targets and deal with the dynamic of the market.

*5.1.2.2 Price bid behavior*

Comparing the annual $PLDh_{average}$ of each scenario (results in Table 5.15) we can notice that the price increases when:

i. the annual water inflow decreases;
ii. the ceiling price moves from the $PLD_{nh}$ rule to the Fixed one; or
iii. there is more leftover stored energy available for BID2 due less ex-ante contracts.

In economic terms, indeed we should expect an increase of the product price when the availability of the resource needed to produce it (water inflow) decreases (item i). So, when moving from a good hydrological year to a medium or a bad one, the electricity short-term price level should rise. The second observation (item ii) corroborates the previous observation because once market participants have opportunity to raise prices and the ceiling price is higher , the price increases.

Lastly, as pointed out by [Rangel, 2008], market power in hydro markets arises from the strategic water management of reservoirs, which means that the reallocation of a given amount of energy across periods can lead to an increase in prices. In the absence of long-term contracts, this author states that the inter-temporal strategic water management could lead to an increase in prices of about 20%. However, if generators are fully contracted the incentive for strategic behavior disappears. This price trend is observed in item iii). Moving from a higher level (100% and 50%) of bilateral contracts to a lower one (50% and 0%) originates a sharp price rise. Figure 5.5 presents the bid prices (dots, each color representing a hydro), ceiling prices (PLDreg_uplim) and final hydro short-term prices (PLDh) for scenario no.1.

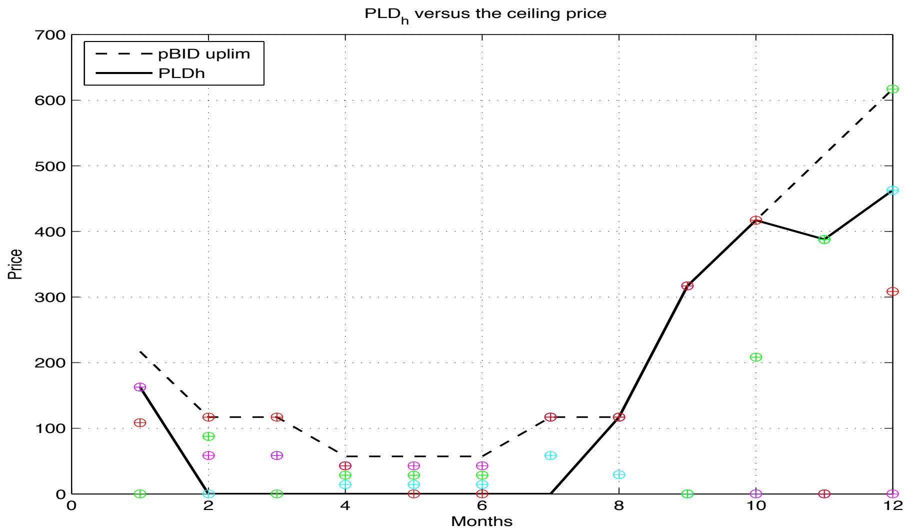


**Figure 5.5 – Price bids versus ceiling price in scenario no. 1 (lowest price)**

While Figure 5.5 illustrates the scenario with the lowest $PLDh_{average}$ (scenario no. 1 has the highest water flow, a "tight" ceiling price rule $PLD_{nh}$, and hydros are 100% committed by ex-ante contracts), Figure 5.6 shows the results obtained for the scenario with the highest $PLDh_{average}$ (scenario no. 18 has the lowest water flow, a "loose" ceiling price rule *FIXED*, and hydros aren't ex-ante committed).

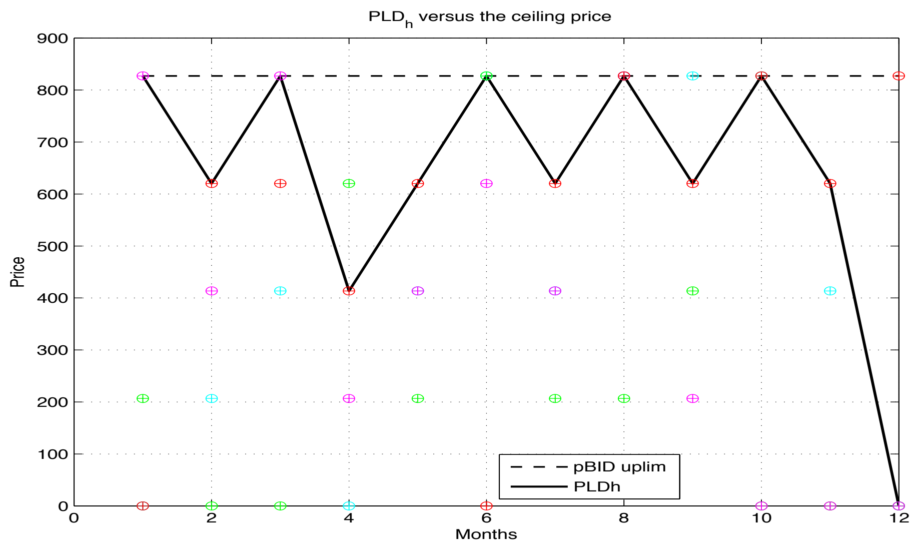


**Figure 5.6 – Price bids versus ceiling price in scenario no. 18 (highest price)**

The statement from [Rangel, 2008] regarding the hydros' influence on price and how ex-ante contracts can be used to avoid the exercise of market power can be noted by comparing Figure 5.6 (scenario no. 18) with Figure 5.7 (scenario no. 16), which is presented below. The only difference between these two scenarios is the level of ex-ante contract imposed to all hydros: while in scenario no. 18 qCE is equal to 0%; in scenario no. 16 qCE is equal 100%. Nevertheless, the average annual hydro short-term market price ($PLDh_{average}$) falls almost 40% when the obligation to be fully ex-ante committed is simulated: in scenario no. 18 $PLDh_{average}$ is equal to $ 638; and in scenario no. 16 $PLDh_{average}$ is equal to $ 345.

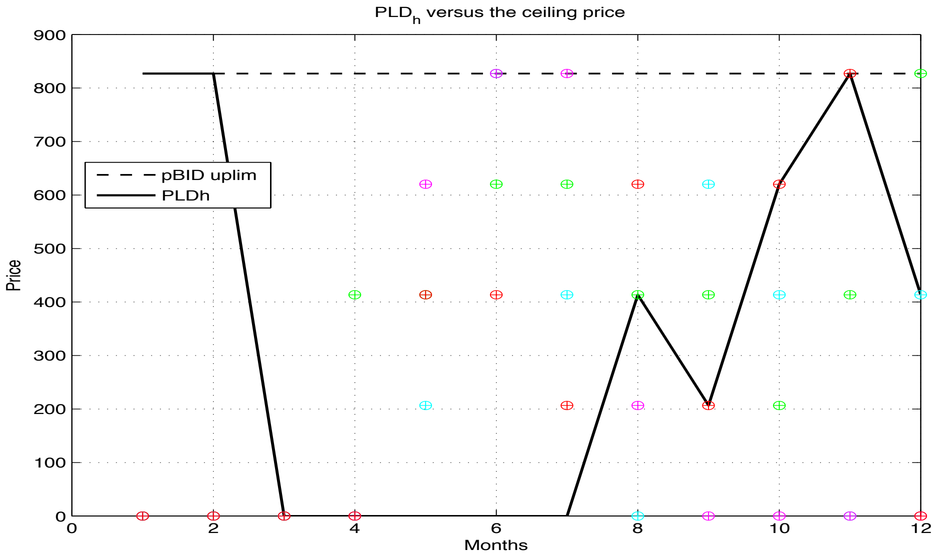


**Figure 5.7 – Price bids versus ceiling price in scenario no. 16 (qCE = 100%)**

### 5.1.3 Final remarks

[Weidlich, 2008] states that credible simulation with ABMs applied in the economic field entails several procedures. First, it has to be ensured that the computational model is correctly implemented and working as intended. This procedure is referred to as verification and mainly consists of debugging the implemented computer program. Calibration, the second procedure, corresponds to the process of selecting the values of parameters so that the correspondence of the model's output with the real-world system is maximized. Finally, in the validation step the modeler has to check whether the simulation model accurately represents the real system being analyzed, from the perspective of the research objectives that the model is applied to.

The developed algorithm, described in detail in section 4.5, was written in Matlab, and the entire debugging process was performed several times. The presented algorithm corresponds to the 12$^{th}$ developed version, and in each version different formulations of the Q-learning and linear programming were implemented and tested. The process of finding and correcting the bugs in the program code was performed, and the entire process of modeling and writing the codes of these alternatives took about 10 months.

The algorithm stops when, for all hydros in the simulation, the sum of the absolute value of the difference between the values of the Q-learning matrix built in a given iteration and the values of the matrix of the previous one is lower than the 0,5% (for BID1) or 5% (for BID2) of the maximum value of the Q-learning matrix. During the process of calibration of the algorithm, distinct values for the parameters α (learning rate) and γ (discount factor) were tested, several convergence criteria were verified (0.5%, 1%, 3% and 5%), and the Q-learning matrices were initialized with different values.

At the end, the α and γ values used in these simulations seem to appropriately serve the purpose of testing the capability of hydro agents learning how to manage the bilateral contracts and the leftover energy. The learning rate α is equal to 0.9 in both BID1 and BID2 because new information coming from each new iteration can strongly influence (and at the same rate) the learning process of the agents. The discount factor γ is equal to zero in BID1 because the focus is to comply with bilateral contracts (no matter what the next stage will be) in order to avoid negative exposition in the current stage. Differently, in BID2 γ is equal to 1 (its highest value) to capture the goal of this bid: to encourage the agents not to be “myopic” by only considering current rewards, but instead to seek for distant payoffs, i.e. future profits in the month-ahead market.

Lastly, let us focus on the validation phase. The current Brazilian power system operates under a centralized dispatch driven by computational software that include dynamic and linear programming tools, while the proposed market design (i.e. the hydro short-term market based on VRM) operates under a decentralized dispatch scheme driven by market based bids. So, once VRM is a new market design never implemented before, the results of the simulations provided by the VRM cannot be validated against market results observed in the Brazilian real electricity market. On the other hand, the analysis of the representativeness of this model concerning the real world is done based on qualitative observations. Thus, the results coming from the aforementioned simulations are examined under the perspective of the real world market forces.

By examining the basis of the criteria that should be fulfilled by an adequate learning algorithm, [Weidlich, 2008] directs the discussion towards the collective and individual rationality of the agents in the framework of electricity markets. Afterwards, she suggest the following questions to address the mentioned capabilities:

Question 1. Collective rationality: Do agents succeed to coordinate on bidding sufficient quantities to satisfy total demand?

Question 2. Individual rationality: Do agents recognize their strategic advantages?

Regarding Question 1, it should be noted that this assessment is not an issue to be imposed over the proposed market design. The usefulness of the VRM is to disconnect the (virtual) bids in the short-term market from the physical quantities coming from the ISO dispatch. As explained in Section 4.2, first the ISO decides the quantity to be supplied by hydros ($Q_h$) and then the hydros compete to supply $Q_h$. Moreover, divergences can perfectly coexist: the ISO’s decision about how to manage the reservoirs to supply the demand over a period ahead can diverge from the decision of the agent to (virtually) do so.

Also, in the VRM a virtual unsupplied demand does not mean a physical load shedding. Thereby, the developed algorithm does not impose penalties to agents when the total supply quantity is less than total demand. If this happens, the market is (virtually) cleared considering that all selling bids are successful ones. Nevertheless, in the algorithm agents have incentives to (virtually) supply the entire demand because in each trading period they have to:

i) Endure bilateral contracts; otherwise they will be negatively exposed, which means economic losses once they need to buy electricity to fulfill their commercial commitments;
ii) Avoid virtual spillage; spillage reflects loss of opportunity since the associated energy is no longer available in the account; and
iii) Seek profit; which implies to sell electricity through bids whereas optimizing the leftover stored energy.

So, despite agents are not forced to supply the total demand, they have incentives to do so. They are totally free to save water and manage their reservoirs according to what they understand to be the best strategy; however, they get a negative signal to do so in terms of the reinforcement learning approach if they don't meet the three conditions enumerated above. Despite Question 1 can be relaxed, indeed very frequently hydros have been coordinating to bid sufficient quantities to satisfy total demand.

Question 2 addresses the individual rationality. To give an example in classical electricity short-term markets, agents with lower marginal generation costs should enhance their chances to have successful bids by submitting lower-price bids while agents with higher marginal costs have to bid at higher prices in order to avoid losses. Drawing a parallel with the proposed model, hydros operating under the VRM should choose their best strategies to optimize their profits regarding both to attempt preventing negative expositions and to sell the excess of energy in the short-term market. So, Question 2 can be split in two sub questions:

Question 2.1. Do agents with ex-ante bilateral contracts offer appropriate pairs of quantity and price bid to avoid negative exposition in the short-term market?

Question 2.2. Do agents offer intelligent bids (e.g. save water in certain moments to be used when prices are higher) to optimize the profit coming from the short-term market?

Considering the simulations of the case study presented before, the following paragraphs are dedicated to answer Questions 2.1 and 2.2.

The results reported in Section 5.1.1 indicate that under several different scenarios, agents are capable of acting on their own in order to seek the best action to endure their bilateral contracts. Agents always adopt action a12 (which means to endure the total amount of ex-ante contracts at the lowest price) in state s1 (ERA > qCE). In state s2 (ERA ≤ qCE), agents also continuously decide to sustain their bilateral contracts as much as possible by offering a qBID equal to the available quantity. In state s2, the bid price (pBID) can vary mainly due to the influence of the annual hydrological pattern. When moving from a good year to a bad one, agents suffer more often with the situation featured by state s2 (ERA ≤ qCE), and then they tend to mitigate their losses by offering bid prices with the highest probability of being successful, which is pBID equal to zero. Concerning the behavior of agents in both states s1 and s2, we come up with the following conclusions:

- The agents are capable of fulfilling the purpose of BID1, which is to learn the best strategies to avoid ending up with a quantity bid (qBID) that will bring them negative exposed positions;
- In the developed Q-learning, the bid price (pBID) equal to zero represents the action with the highest probability to be successful. If an agent offers energy at a higher price, the probability of not being dispatch increases;
- When there is plenty of water (e.g. months with high water flows), pBID is at the lowest level due to the abundance of this resource and the need to compete to endure contracts; and
- When there is severe water scarcity (e.g. the dry months of the year with bad water flows), pBID is also at the lowest level because, even though the resource is rare, there is the need to compete to endure contracts. In a situation like this, there is no leftover energy to be used in BID2. The agent has little amount of energy in his ERA and has to use it wisely. Additionally, it is more important for him to fulfill the ex-ante contracts. Then, the best way to use the available energy is to offer it at a lower price in order to be dispatched (and sustain contracts).

After complying with the bilateral contracts, the results of this simulation also reveal that agents can manage their reservoirs in order to optimize the leftover stored energy. This part of the algorithm (as shown in Section 4.5.2) combines a goal-oriented scheme, built through the mentioned linear programming, with a goal-oriented learner from the Q-learning. These two characteristics correspond to two important required features of software agents from the artificial intelligence world: agents are goal-oriented in that they seek to maximize an assigned value like payoff, fitness or utility; and agents are adaptive, meaning that they learn which actions to take in order to increase this value over time, and so reach their goal [Weidlich, 2008].

Through the performed simulations, we can notice that both quantity and price bid strategies are consistent with what is expected in real electricity markets. Regarding the quantity bid behavior, the $factor_{goal\_t}$ plays a relevant role. It takes into account that agents will offer in BID1 a qBID equal to qCE or as closer as possible to qCE. Then, this $factor_{goal\_t}$ guides agents in BID2 to the closest possible to the ideal reservoir level. Nevertheless, due to competition, agents have to adapt to the trajectory previously laid down by $factor_{goal\_t}$. So, at the end of the learning process, agents end up with the best action to be taken considering the interaction with other players.

When there is not enough energy from BID1 to supply the total demand, price bids from BID2 (pBID2) are responsible for the formation of the hydro short-term market price ($PLD_h$). Otherwise, when all demand is supplied by BID1, it is the pBID1 that will influence the final price. Bearing in mind the overview of the price profile in different scenarios, the obtained results were consistent with what should be expected: when the water flows decrease, prices increase; if there is more space to practice higher bid prices due the ceiling price, prices increase; and when hydros are not constrained by ex-ante contracts, prices also increase.

All that said, we believe that the ABM with Q-learning developed to simulate the hydros' interaction into the short-term market under the rules of the VRM suitably embodies the main market forces that exist in the real world. So, it is ready to be applied to the simulation of the Brazilian electricity market as it will be described in the next section.

## 5.2 Simulation of the Brazilian electricity market

Since one of the objectives of this thesis is to analyze the performance of the proposed VRM within the Brazilian electricity market, a major effort was undertaken to use in the simulations accurate and comprehensive data from Brazil.

So, a total of 125 hydro power plants were simulated. This represents more than 98% of the total hydro installed capacity in the country. Appendix A presents the corresponding data, such as the starting operation year or when it was connected to the National Interconnected System (known in Brazil by the acronym *SIN*), if the hydro has a reservoir (wr) or a run-of-the-river type (rr), the geographic area where it is located (N for *North*, NE for *Northeast*, SE-CO for *Southeast-Midwest*, and S for *South*), the submarket where the hydro belongs to (N, NE, SE-CO or S), its installed capacity (IC), its physical guarantee (PG), its reservoir capacity (RC), and the level of the reservoir in the beginning of the years 2012, 2013 and 2014.

Besides the data about hydros, there is also market data embracing the 3 last years (2012, 2013 and 2014) as the monthly total demand ($Q_{total}$) supplied by all power plants in the country into SIN[51], as well as its corresponding total demand supplied by all hydropower plants ($Q_h$) and non-hydropower plants ($Q_{nh}$). In addition, it also considers for each month of these three years the variable cost of the last non-hydropower dispatched plant (PLDnh_SIN), the regulatory ceiling price (PLDreg_uplim), the total physical guarantee of the hydros ($PG_{total}$), the total hydro physical guarantee into each submarket (PG_N for the *North*, PG_NE for the *Northeast*, PG_SE-CO for the *Southeast-Midwest* and PG_S for the *South* submarket), and the total natural affluent energy that flowed monthly into the SIN (NAE_SIN) and its consonant values for each geographic area (NAE_N, NAE_NE, NAE_SE-CO, and NAE_S). All these values are presented in Appendix B (Data regarding the Brazilian electricity market adopted in the simulation).

For each year, these simulations consider three levels of ex-ante contract (95%, 50% and 0%), two types of the seasonalization of the bilateral contracts (*NAE,* in which the annual amount is allocated bearing in mind weights determined by the water inflow; and *FLAT,* where the annual energy committed through contracts is monthly distributed in equal amounts), and two types of ceiling price rules (*PLDnh*, i.e. equivalent to the variable cost of the last non-hydro station dispatched by the ISO; and *Fixed,* a fixed ceiling price equal to the annual ceiling price established by the national regulatory agency). This said, 12 scenarios were performed in each year.

Each simulation takes about 12 minutes to converge, corresponding to around 1.100 years of learning to reach the final results. Regarding the parameters of the Q-learning, it was used the

[51] Only 1.7% of the electricity demand required by the country is located outside the SIN [ONS, 2014b].

same learning rate α and discount factor γ adopted in the validation phase the algorithm (as defined in Section 5.1, α is equal to 0,9 in both BID1 and BID2, and γ is equal to 0 in BID1 and equal to 1 in BID2). The parameters of the Simulating Annealing (Section 4.4) are also the same earlier used (for BID 1: Temp is equal to $10^{13}$ and $\Phi$ is equal to 0.8; for BID2: Temp is equal to $10^{14}$ and $\Phi$ is equal to 0.95).

The next three sections present the results for the years 2012, 2013 and 2014. In 2012 Brazil had a Long-Term Average (known in Brazil by the acronym *MLT*) equals to 80,04%, which means that the amount of water that flowed into the SIN during one year was equivalent to 80,04% of the average calculated by the historic of 82 years of equivalent data. In 2013 and 2014, the *MLT* is equal to 92,97% and 88,52%, respectively. In other words, in these three years Brazil faced an unfavorable period for the production of hydroelectric, characterized by inflows (and thus NAE) significantly below the historic average.

### 5.2.1 Year 2012

Table 5.17 presents the comparison between the actual monthly short-term price (*PLD*), computed as explained in Section 3.2.3, and the new *PLD* resulting from the simulation, taking into account the VRM designed in Section 4.2 and the algorithm described in Section 4.5.

**Table 5.17 – Year 2012: Actual monthly PLD versus new PLD**

| **Actual data from the current Brazilian market** | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| PLDnh | 18 | 32 | 117 | 188 | 181 | 119 | 91 | 119 | 183 | 288 | 376 | 256 | 163,9 |
| PLDreg_uplim | 727,52 | | | | | | | | | | | | |

| **Scenarios** | | | | **Results** | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Ceiling price rule*** | ***Seaso.*** | ***qCE level*** | **no.** | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| ***PLDnh*** | *FLAT* | 95% | 1 | 2 | 3 | 37 | 29 | 31 | 18 | 33 | 44 | 147 | 178 | 172 | 112 | 67,1 |
| | | 50% | 2 | 2 | 3 | 37 | 69 | 68 | 18 | 52 | 94 | 110 | 233 | 240 | 112 | 86,6 |
| | | 0% | 3 | 2 | 3 | 37 | 69 | 106 | 43 | 52 | 94 | 183 | 178 | 172 | 160 | 91,7 |
| | ***NAE*** | **95%** | **4** | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 74 | 288 | 240 | 160 | **77,7** |
| | | 50% | 5 | 2 | 3 | 11 | 69 | 68 | 43 | 33 | 94 | 183 | 288 | 308 | 208 | 109,1 |
| | | 0% | 6 | 2 | 3 | 90 | 69 | 68 | 68 | 33 | 119 | 183 | 288 | 240 | 256 | 118,3 |
| *Fixed* | *FLAT* | 95% | 7 | 2 | 3 | 176 | 29 | 182 | 18 | 169 | 172 | 182 | 346 | 236 | 201 | 142,9 |
| | | 50% | 8 | 2 | 3 | 176 | 29 | 182 | 18 | 169 | 172 | 327 | 484 | 367 | 201 | **177,4** |
| | | 0% | 9 | 2 | 167 | 176 | 183 | 182 | 18 | 169 | 326 | 327 | 623 | 498 | 337 | **250,6** |
| | *NAE* | 95% | 10 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 326 | 471 | 484 | 236 | 337 | 163,4 |
| | | 50% | 11 | 2 | 3 | 176 | 183 | 333 | 18 | 324 | 326 | 615 | 484 | 236 | 473 | **264,4** |
| | | 0% | 12 | 2 | 3 | 176 | 183 | 182 | 172 | 324 | 326 | 471 | 623 | 630 | 337 | **285,6** |

As can be observed, just in scenarios no. 8, 9, 11 and 12 the annual average PLD ($PLD_{average}$ value in bold) is higher than the actual annual average PLD. And even in the scenarios with the

*Fixed* ceiling price rule, where the regulatory price (PLDreg_uplim) is equal to R$ 727,52, the resulting monthly PLDs are at a considerable low levels during several months.

As it was already noticed during the validation phase of the algorithm (in particular when analyzing the price bid behavior, in Section 5.1.2.2), annual average prices increase when: i) the ceiling price moves from the PLDnh rule to the *Fixed* one; and ii) there is more leftover stored energy available for BID2 due less ex-ante contracts (i.e. when qCE decrease). In addition, these prices also increase when moving from the scenarios with *FLAT* seasonalization to the *NAE* one, what is the expected since in *NAE* scenarios there is higher flexibility to raise the price. This flexibility comes from the fact that, the same way that price increase when qCE (and thus qBID1) decrease, when seasonalization is performed in the NAE mode the value of qCE (and thus qBID1) is also very low during the months with low water inflow. This allocates more available energy to qBID2 in the other months, which pushes price up.

It is known that companies in Brazil, during the years 2012, 2013 and 2014, usually had committed by bilateral contracts values close to 95% of its physical guarantee (i.e. qCE equal to 95%). Furthermore, in 2012 all market participants trading in the Brazilian short-term market had their energy valued by the variable cost of the last dispatched resource (if this resource is a thermal power plant) or by the minimum ceiling price (when just hydros are dispatched), and these limits are incorporated in *PLDnh* ceiling price rule. So, considering that companies tend to perform a seasonalization that somehow follows the water inflows pattern (i.e. NAE mode), scenario no. 4 is indeed close to the current Brazilian electricity market. This fact makes scenario no. 4 (cells shaded in gray in Table 5.17) the most important one. So, now focusing in scenario no. 4, the comparison between the actual annual PLDaverage (163,9 R$/MWh) and the resulting annual PLDaverage (77,7 R$/MWh) emphasizes a sharply decrease of price when the VRM is used. This finding also occurs when comparing the monthly price values.

In the following, the results regarding qBID1 and qBID2 from the Brazilian nine largest (in terms of installed capacity) hydropower reservoir plants are presented. As can be noticed in Figure 5.8 (lines are qCEs and dots are qBID1s), hydros are able to learn to sustain their bilateral contracts. This is done once hydros are choosing qBID1 as close as possible to qCE. Only hydro Tucuruí, during some periods, cannot monthly endure 100% of the bilateral contract by qBID1. This happened because Tucuruí was with a low level in the beginning of the simulation (35,73% of the reservoir level), it had to comply with 95% of its physical guarantee (scenario no. 4 has qCE equal to 95%), and 2012 was a year with a Long-Term Average (*MLT*) equal to 80,04% (i.e. bad hydrological year).

This feature can also be observed when analyzing the results from qBID2. Regarding the second bid, Figure 5.9 presents the "map" with the best strategy for these nine main hydros. These 3D graphics show in the vertical axe the value of each cell of the Q-learning matrix[52]. So, the top of the "mountains" represents the best action to be taken in each month.

[52] The representation of Q-learning matrix for BID2 is in Table 4.3.

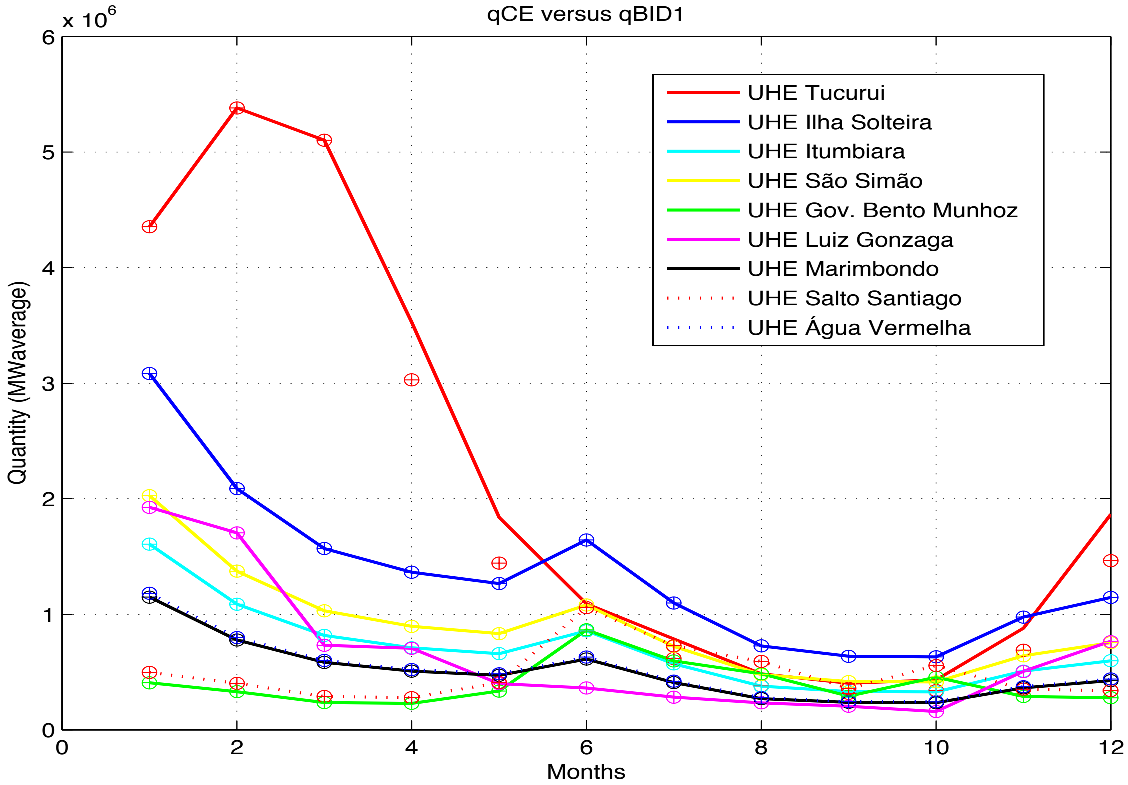


**Figure 5.8 – qBID1: Sustaining the bilateral contracts in 2012 (scenario no. 4)**

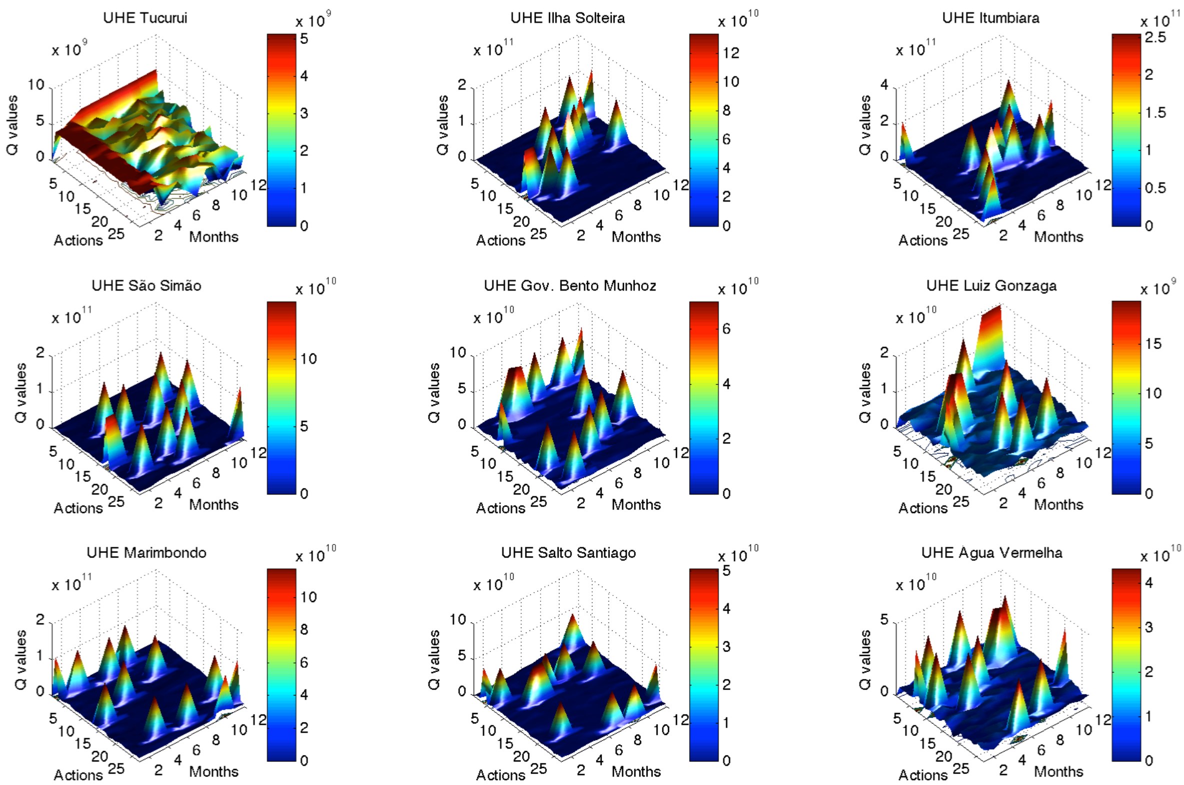


**Figure 5.9 – qBID2: Best strategy to use the leftover energy in 2012 (scenario no. 4)**

Unlike the other eight hydros, Tucuruí has a "mountain range" (instead of several separate "mountains") located at the action a1. Action a1 means that the company should offer a qBID2 and a pBID2 equal to zero, and this action is chosen whenever a hydro doesn't have water to use in BID2 (i.e. all water was previously used by BID1 to comply with contracts). Additionally, despite the fact that Figure 5.8 addresses qBID1 and Figure 5.9 displays results for qBID2, these two sets of graphics can be seen as complementary to each other.

### 5.2.2 Year 2013

As presented in Table 5.18, during the year 2013 all resulting $PLD_{average}$ are lower than the actual $PLD_{average}$. The results for scenario no. 4 (the most representative scenario of the current Brazilian market) are highlighted in the table. In this year the monthly short-term prices coming from the VRM simulation of scenario no. 4 (cells shaded in gray) are well below than the actual values observed in the current Brazilian market.

**Table 5.18 – Year 2013: Actual monthly PLD versus new PLD**

| Actual data from the current Brazilian market | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| PLDnh | 412 | 214 | 340 | 196 | 345 | 207 | 117 | 159 | 263 | 252 | 331 | 291 | 260,5 |
| PLDreg_uplim | 727,52 | | | | | | | | | | | | |

| Scenarios | | | | Results | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Ceiling price rule* | *Seaso.* | *qCE level* | nº | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| ***PLDnh*** | *FLAT* | 95% | 1 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 65 | 62 | 209 | 68 | 77,1 |
| | | 50% | 2 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 209 | 68 | 89,1 |
| | | 0% | 3 | 102 | 51 | 78 | 46 | 91 | 56 | 50 | 129 | 164 | 252 | 209 | 124 | 112,6 |
| | ***NAE*** | **95%** | **4** | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 209 | 68 | **89,1** |
| | | 50% | 5 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 164 | 157 | 270 | 124 | 100,5 |
| | | 0% | 6 | 102 | 51 | 78 | 46 | 91 | 56 | 50 | 100 | 214 | 204 | 209 | 180 | 114,9 |
| *Fixed* | *FLAT* | 95% | 7 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 212 | 356 | 375 | 68 | 125,2 |
| | | 50% | 8 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 186 | 359 | 356 | 375 | 218 | 162,0 |
| | | 0% | 9 | 102 | 51 | 78 | 46 | 91 | 198 | 176 | 186 | 359 | 209 | 375 | 218 | 173,9 |
| | *NAE* | 95% | 10 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 186 | 212 | 209 | 375 | 68 | 125,1 |
| | | 50% | 11 | 102 | 51 | 78 | 46 | 91 | 56 | 176 | 186 | 359 | 356 | 375 | 68 | 161,9 |
| | | 0% | 12 | 102 | 51 | 78 | 46 | 91 | 56 | 176 | 186 | 359 | 209 | 519 | 218 | 174,1 |

Figures 5.10 and 5.11 present, respectively, how hydros (through BID1) sustained their contracts and what is the best strategy to use the leftover energy (through BID2). Again, hydro Tucuruí, due the same reasons already enumerated for 2012 (reservoir level at 25,35%, *MLT* equal to 92,97%, and qCE equal to 95%), was not able to uphold 100% of its bilateral contract (red dots below the red curve in Figure 5.10), resulting in shortage of water for BID2 ("mountain range" at action a1 in Figure 5.11).

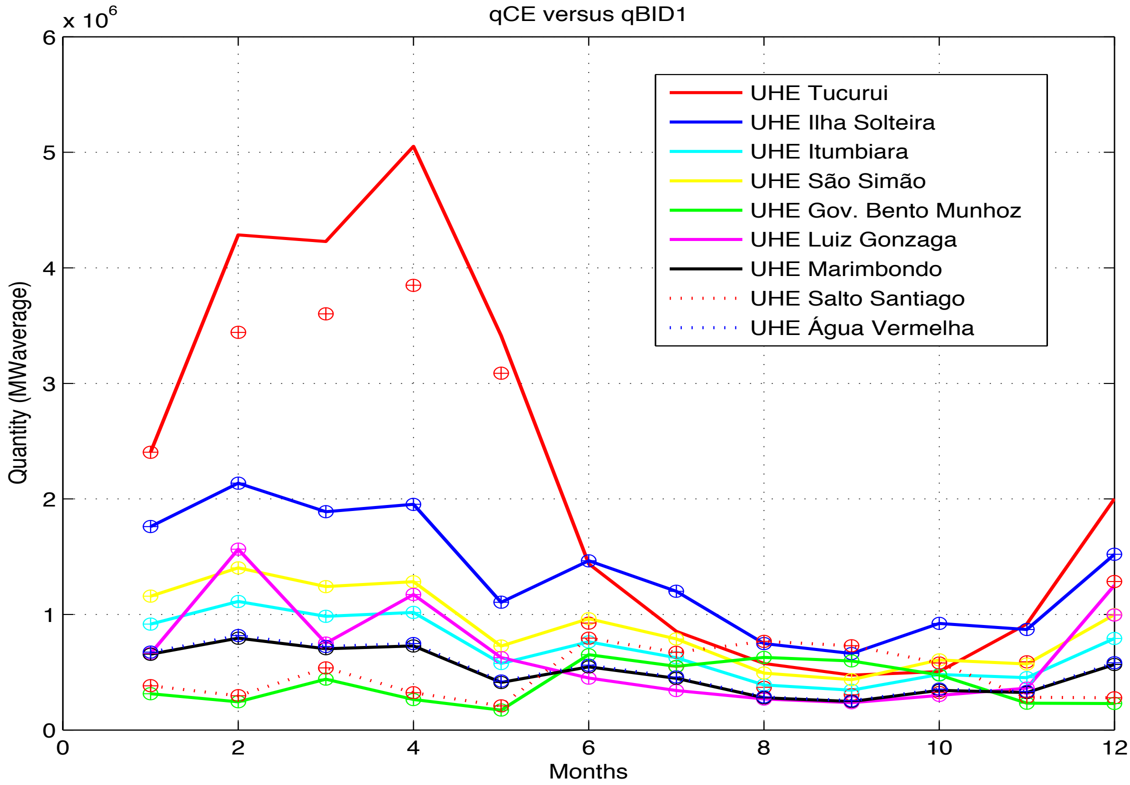


**Figure 5.10 – qBID1: Sustaining the bilateral contracts in 2013 (scenario no. 4)**

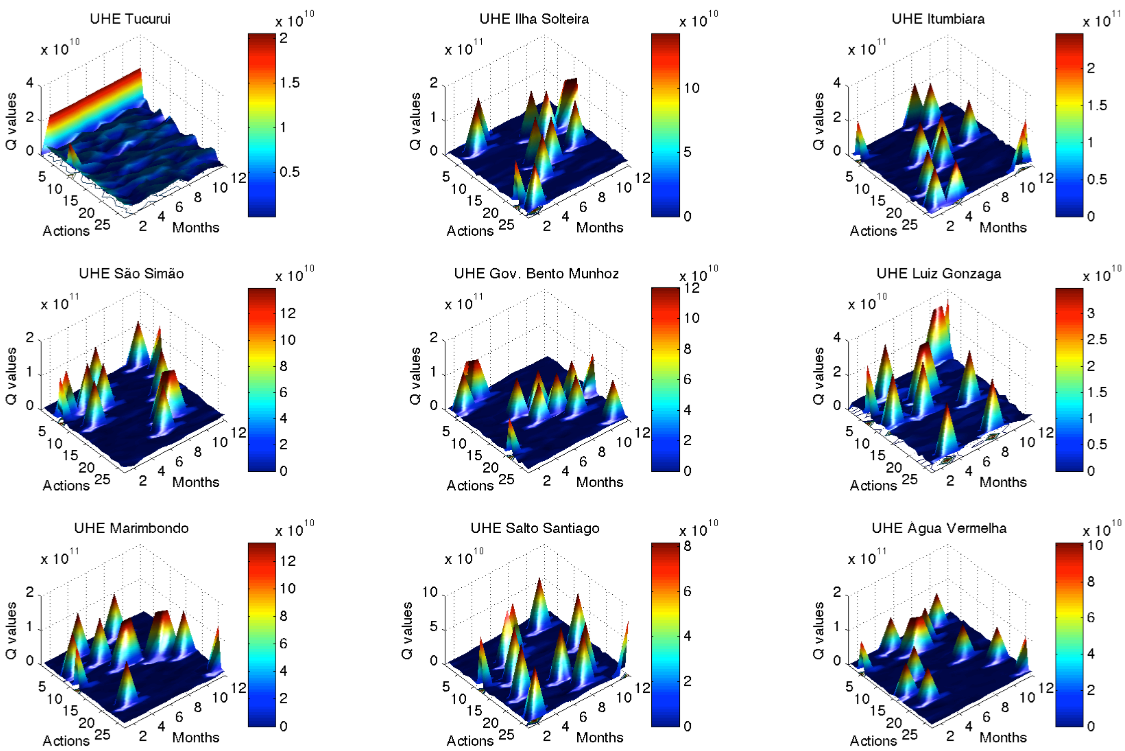


**Figure 5.11 – qBID2: Best strategy to use the leftover energy in 2013 (scenario no. 4)**

### 5.2.3 Year 2014

As shown in Table 5.19, in 2014 and regarding the price bids there is no resulting $PLD_{average}$ higher than actual $PLD_{average}$. Focusing only on scenario no. 4, it is also possible to realize how low the monthly prices coming from the VRM are if comparing them to the actual data. Again, even considering the scenarios with the *Fixed* ceiling price rule (scenarios no. 7, 8, 9, 10, 11 and 12) the annual $PLD_{average}$ is lower than the actual one (R$ 653,5).

**Table 5.19 – Year 2014: Actual monthly PLD versus new PLD**

| Actual data from the current Brazilian market | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| PLDnh | 375 | 714 | 775 | 758 | 680 | 361 | 570 | 710 | 729 | 766 | 805 | 601 | 653,5 |
| PLDreg_uplim | 727,52 | | | | | | | | | | | | |

| Scenarios | | | | Results | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *Ceiling price rule* | *Seaso.* | *qCE level* | nº | monthly PLD (R$/MWh) | | | | | | | | | | | | $PLD_{average}$ |
| | | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | |
| ***PLDnh*** | *FLAT* | 95% | 1 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 270 | 544 | 212 | 258,4 |
| | | 50% | 2 | 82 | 314 | 216 | 215 | 215 | 116 | 278 | 368 | 370 | 518 | 544 | 212 | 287,2 |
| | | 0% | 3 | 156 | 447 | 216 | 215 | 331 | 116 | 278 | 596 | 609 | 766 | 413 | 309 | 370,9 |
| | ***NAE*** | **95%** | **4** | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 489 | 518 | 413 | 212 | **267,1** |
| | | 50% | 5 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 489 | 642 | 674 | 212 | 299,1 |
| | | 0% | 6 | 82 | 314 | 216 | 215 | 215 | 116 | 278 | 596 | 609 | 766 | 413 | 212 | 335,9 |
| *Fixed* | *FLAT* | 95% | 7 | 82 | 488 | 216 | 215 | 215 | 116 | 181 | 254 | 250 | 536 | 550 | 212 | 276,1 |
| | | 50% | 8 | 243 | 642 | 216 | 215 | 215 | 116 | 181 | 518 | 385 | 403 | 683 | 212 | 335,6 |
| | | 0% | 9 | 243 | 334 | 216 | 362 | 355 | 116 | 462 | 386 | 385 | 403 | 416 | 345 | 335,3 |
| | *NAE* | 95% | 10 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 386 | 520 | 403 | 683 | 212 | 284,1 |
| | | 50% | 11 | 82 | 488 | 216 | 215 | 215 | 116 | 321 | 518 | 520 | 669 | 550 | 212 | 343,5 |
| | | 0% | 12 | 403 | 181 | 364 | 215 | 215 | 116 | 321 | 386 | 520 | 536 | 683 | 345 | 357,1 |

Regarding the quantity bids (Figure 5.12 and Figure 5.13), all hydros sustained their contracts, except Tucuruí and Luiz Gonzaga. Just to give more details about these two hydros, Table 5.20 presents the percentage of sustained contract ($qCE_t/qBID1_t$) in each month.

**Table 5.20 – Year 2014: percentage of sustained contract**

| Hydros | Months | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Tucuruí | 100% | 100% | 89% | 97% | 100% | 94% | 100% | 77% | 73% | 73% | 73% | 73% |
| Luiz Gonzaga | 100% | 100% | 76% | 75% | 88% | 60% | 72% | 60% | 60% | 60% | 60% | 60% |

The values below 100% happen because in 2014 Tucuruí and Luiz Gonzaga started the year with 44,23% and 42,02% of the reservoir, respectively. Additionally, 2014 is a year having *MLT* equal to 88,52%, i.e. with water inflows 11,48% below of the average of a historical series of 84 years. So, given these circumstances, there is nothing that they can do to avoid this.

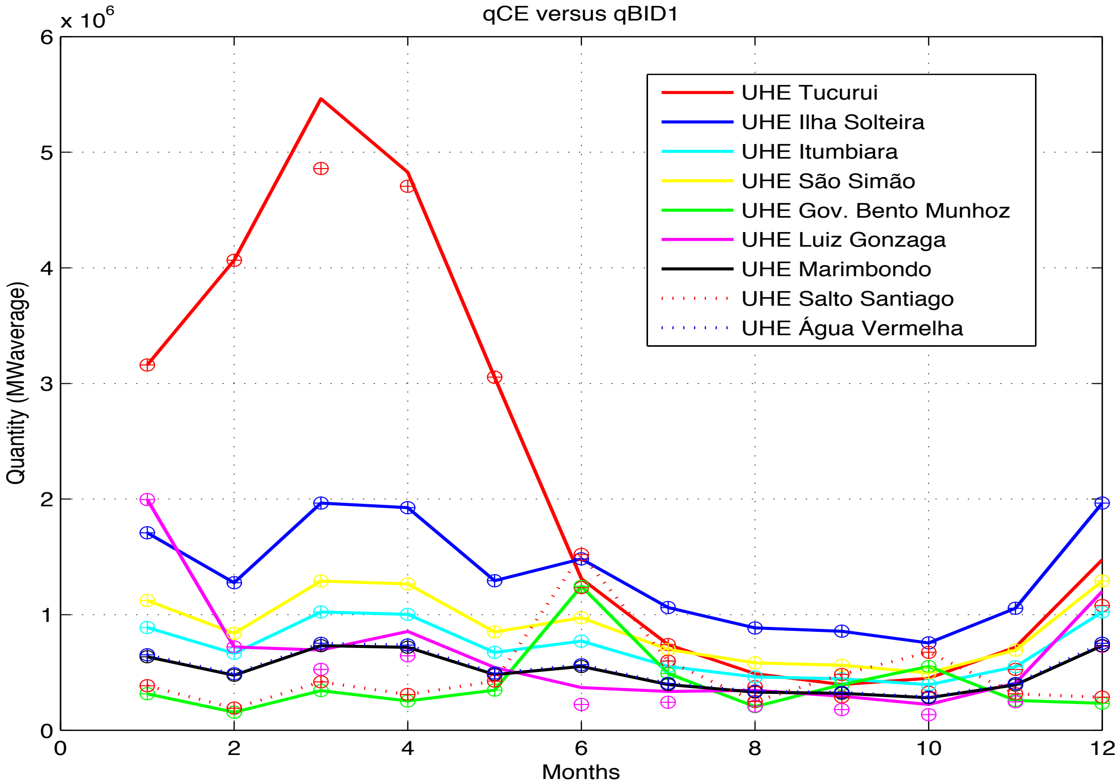


**Figure 5.12 – qBID1: Sustaining the bilateral contracts in 2014 (scenario no. 4)**

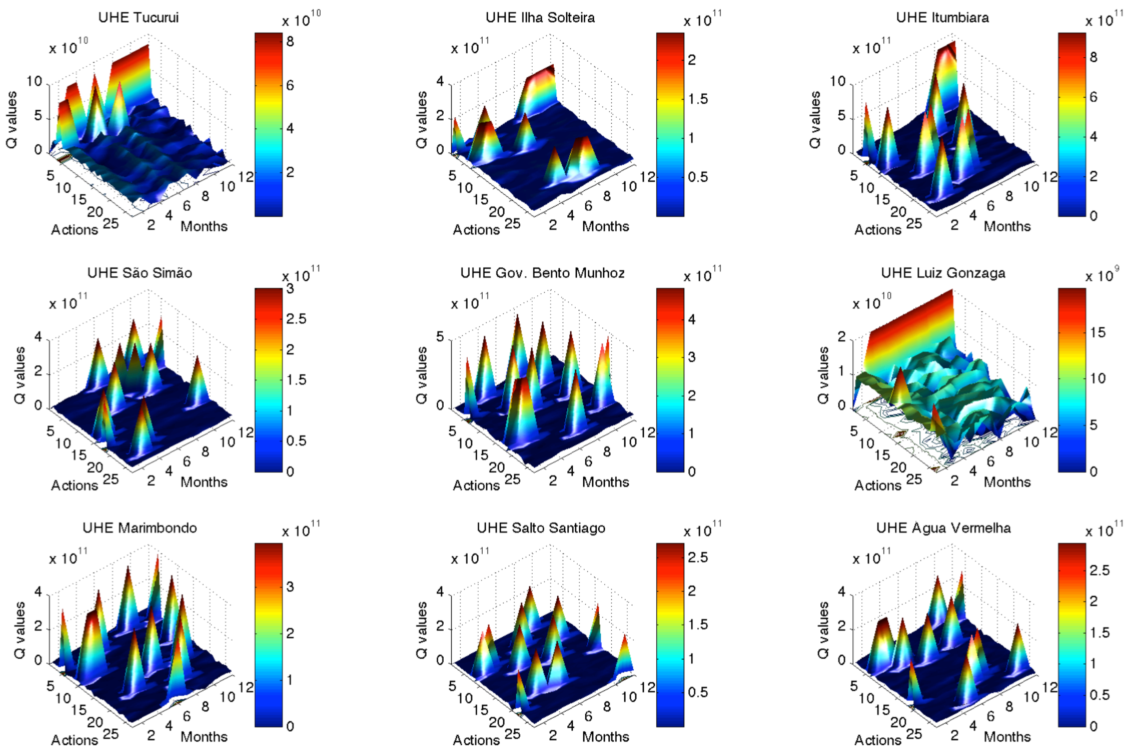


**Figure 5.13 – qBID2: Best strategy to use the leftover energy in 2014 (scenario no. 4)**

### 5.2.4 Final remarks

#### *5.2.4.1 Run-of-the-river hydros*

The results for the run-of-the-river hydros were not presented so far because, under the point of view of the VRM, there is no complexity in terms of strategy for this kind of hydros. They don't have a reservoir to be managed, so what they just have to do is to sustain contracts through qBID1 and offer all the leftover energy through qBID2 into the same account period (month), otherwise they will have spillage. Besides, they were modelled to offer the qBID2 at a price (pBID2) equal to zero, which is their marginal cost. So, they can be seen as price takers within the uniform pricing rule of the VRM. To put it in numbers, what the nine largest run-of-the-river hydros did to comply with their contracts in 2014 is presented in Figure 5.14.

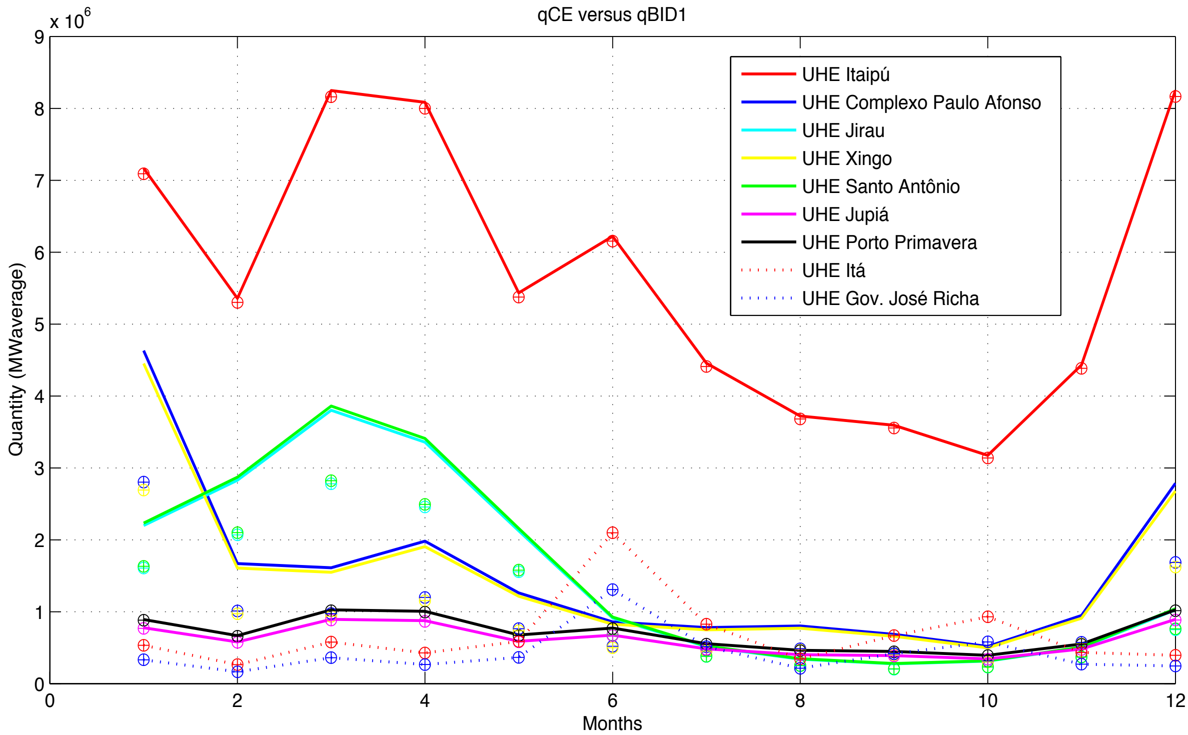


**Figure 5.14 – qBID1 (run-of the river): Sustaining the bilateral contracts in 2014 (scenario no. 4)**

Despite these hydros are run-of-the-rivers, this doesn't mean that they are smaller than those with reservoir in terms of installed capacity. Indeed, among them there are some that are in the list of the largest hydropower plants in the world (e.g. Itaipú, with 14 GW of installed capacity, is the world's second largest hydropower plant, just behind Three Gorges Dam). Still, the results indicate that this kind of hydros act the same way as the hydros with reservoir: offer (through qBID1) as much as possible of energy to endure the bilateral contracts (qCE).

#### *5.2.4.2 Virtual reservoir versus Physical reservoir*

Now considering both the run-of-the-river and with reservoir hydros, the resulting best strategies to sustain contracts (set of actions regarding BID1) and to optimize the leftover energy (set of actions regarding BID2) guide the company to a reservoir level curve throughout the year that can be, as explained in Section 4.2.1 (in particular through Figure 4.3 and Figure 4.4), different from what was decided by the ISO. So, strictly speaking, the virtual reservoir levels can diverge from the physical reservoir levels. In order to compare these two levels of the reservoir, the virtual and the physical one, Appendix C presents the graphics of the nine largest (regarding installed capacity) hydropower plants with reservoir in Brazil in 2012, 2013, and 2014.

To recap, the linear programming inside of the algorithm (addressed in Section 4.5.2) was designed to ensure that the reservoir will reach as much as possible 25% of its total capacity in the last month of the simulation (month 12). This was formulated to guarantee that hydros have a safety stock of water to start the next year. Going back to the Appendix C, we observe that, in these three years, there is a large occurrence of virtual levels close to the physical levels. More than 50% of the hydros in the sample have similar monthly patterns, and among these more than half ended the year with the virtual level close to the physical one.

In this sample, only Tucuruí hydro presents a large gap between the virtual and the physical levels, and during these three years the shape of the two curves are pretty much the same way. This is because:

- on one hand (*virtual world* with commercial purposes), 2012, 2013 and 2014 are years characterized by bad hydrological patterns, and Tucuruí always starts the year with the reservoir at a low level. So, the outcomes of the algorithm indicate that, to comply with the contracts, Tucuruí has to use all the available energy in qBID1 (qBID2 has to be equal to zero in several months, as reported in previous sections), which pushes the agent to end several months of the year with reservoir at zero level;
- on the other hand (*physical world* with physical effects), the ISO operates this reservoir in a particular way. In fact, the ISO adopts energy policy to save water in order to avoid that the reservoir reaches low levels once it could jeopardize the supply of the demand at the end of the dry season and during the peak hours As explained by the ISO in his Energy Operation Plan 2012/2016:
    - "The hydrological behavior of the Tocantins River basin, with large inflows recorded in each wet season, brings the certainty of total refill of Tucuruí reservoir at the end of the wet season and significant spillages in the Northen subsystem. Nevertheless, the depletion of this reservoir causes significant loss of power availability and could risk the supply of the demand at the end of the dry season. Thus, the ONS adopts in the SIN operation, for the month of June, an operating curve of the Tucuruí reservoir that provides a guideline for its annual depletion, minimizing spillages next to the wet season and avoiding the lack of sufficient availability at the end of dry season to serve the subsystem load requirements, especially at peak hours" [ONS, 2012].

Therefore, Tucuruí exemplifies cases where there are two distinct and conflicting interests: the ISO saves water and the Agent uses water. This situation was previously illustrated by Figure 4.4 (Section 4.2.1). On balance, from the commercial point of view the Agent took the best decision once he was able to uphold a higher quantity of energy committed by bilateral contracts than the ISO; however, from the power system operation point of view, the ISO acts based on certain requirements in order to ensure a proper service. At the end, the overall picture confirms that the VRM is able to provide flexibility to sustain the contracts while the operation of the power system remains the same.

*5.2.4.3 Generation Scaling Factor (GSF)*

In the previous section it was pointed out that in the VRM hydros have flexibility to comply with their contracts while the ISO continues his work as it is currently done (ensuring the adequate supply of electricity, regarding the efficiency in the use of energy resources and security of supply of the power system). So, once the “individual” performances are optimized, from both the commercial point of view of the agents and the ISO physical system operation, in this section we examine, under a "global" point of view, whether the VRM is capable of providing a framework in which hydros operate more efficiently in periods of low hydrology when compared with the current model.

The indicator that embodies this overview about the market is the GSF (Generation Scaling Factor), described by equation 3.6 in Section 3.3.3. Currently in Brazil, the GSF is used to check the amount of energy generated by MRE hydropower plants compared to their physical guarantee. If the result is less than 1, hydros are generating less energy than their physical guarantee[53]. In other words, the sum of the electricity production of all hydros into the *MRE* in Brazil[54] is lower than the sum of the physical guarantee of these hydros.

An annual GSF lower than 1 happens when, over the months and all over the country, the ISO dispatches hydros lower than what historically they are able to generate. As previously explained, Brazil has gone through an extended period of water scarcity in recent years (2012 has a *MLT* equal to 80,04%, 2013 92,97%, and 2014 88,52%), which is leading the ISO to dispatch more thermal power plants and less hydros. Table 5.21 shows the comparison between the current annual GSF [CCEE, 2015b] and the GSF from the VRM simulations as they were obtained for scenario no. 4.

**Table 5.21 – Resulting GSF from the simulation (VRM) versus actual data (Brazil)**

| Year | Data | GSF | VRM/Brazil (%) |
|---|---|---|---|
| 2012 | VRM | 1,09 | 100,9% |
| | Brazil | 1,08 | |
| 2013 | VRM | 0,98 | 99,0% |
| | Brazil | 0,99 | |
| 2014 | VRM | 0,92 | 101,1% |
| | Brazil | 0,91 | |

[53] To recap, the hydros physical guarantee corresponds to the maximum energy production that can be maintained almost continuously over the years, simulating the occurrence of thousands of inflow sequences created statistically and assuming a certain risk of not feeding the load [ANEEL, 2013].

[54] Almost all hydros in Brazil participate of this mechanism (*MRE*). What happens sometimes is that some hydros, as a penalty measure, are excluded from the *MRE*.

So, the results from the simulation indicate that in 2012 and 2014 the VRM performed lightly better than the current Brazilian model (in 2012 the $GSF_{VRM}$ is 0,9% higher than $GSF_{Brazil}$, and in 2014 this number increase to 1,1%), and in 2013 the VRM was slightly worse (1% lower).

When moving from the annual analysis to a monthly examination of this indicator, we also observe that during a period the VRM performances better, while in other periods its performance is worse. To provide a closer look in these results, Figure 5.15, Figure 5.16 and Figure 5.17 compare the VRM and the Brazil values for 2012, 2013 and 2014.

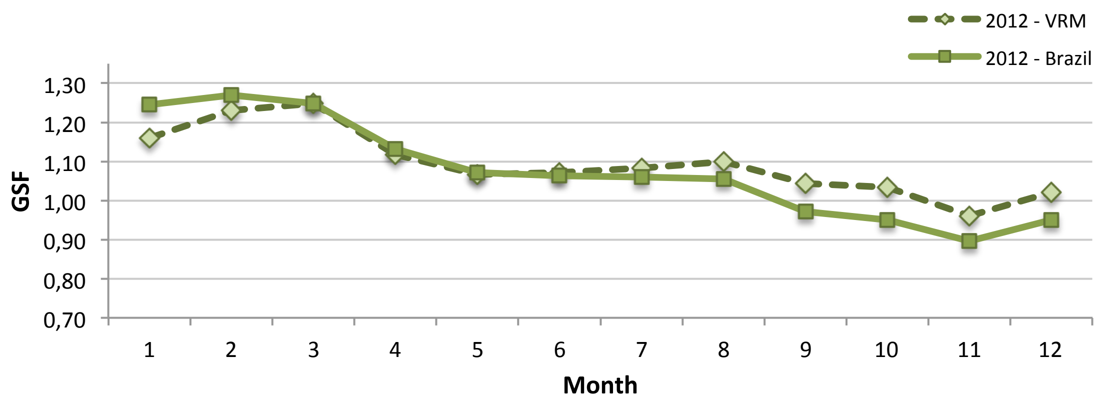


**Figure 5.15 – GSFs in 2012: VRM versus Brazil**

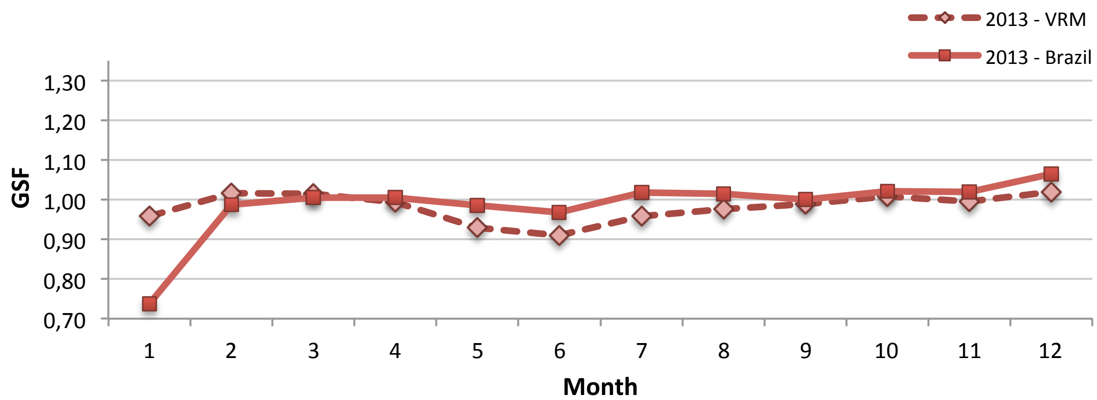


**Figure 5.16 – GSFs in 2013: VRM versus Brazil**

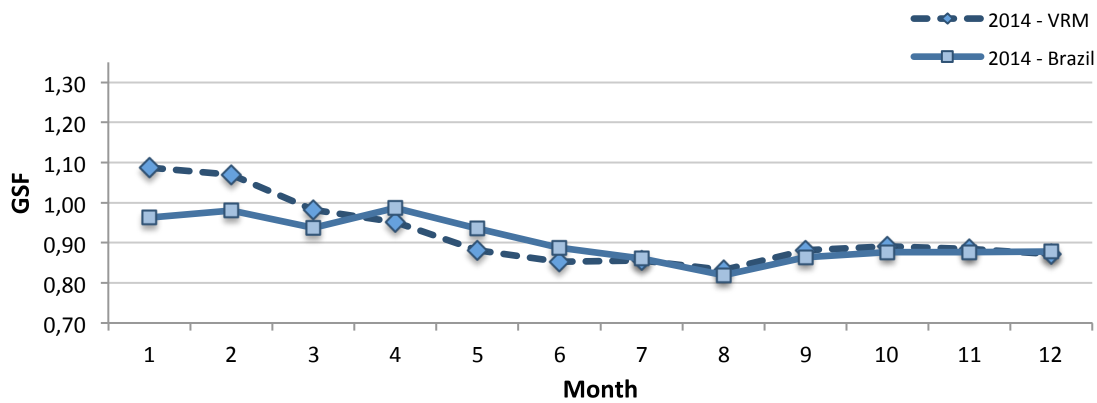


**Figure 5.17 – GSFs in 2014: VRM versus Brazil**

Lastly, having into consideration the overall picture provided by the comparison of these three years, the answer to the raised question in the beginning of this section seems to be: from a "global" point of view, the VRM is neither better nor worse than the current model. This conclusion presents itself as a promising finding, given that there is an improvement at the individual levels (more flexibility), while the overall result remains essentially at the same level.

*5.2.4.4 Short-term price (PLD)*

According to [Weidlich, 2008], the majority of processes in Agent Based Model simulations are stochastic in nature, and some variation around the results can be observed. So, to enhance the robustness of the outcome "short-term price" (i.e. *PLD*), it was used a Monte-Carlo simulation to assess this stochastic nature. This method leads to produce N independent runs, by which the mean and variance of the sample are calculated. The N number of runs required to obtain sufficiently stable estimates of the mean and variance is defined by the convergence criterium. In Monte-Carlo sampling this criterium is often based on the relative uncertainty of the estimative $\beta$, which is given by equation 5.1 [Pereira et. at., 1992].

$$\beta^2 = \frac{V(F)}{N\,.E(F)^2} \tag{5.1}$$

Where:

F is the function that provides a measure of the system;

E(F) is the estimate of expected value of F;

V(F) if the variance of F;

N is the size of the sample.

Briefly, in each iteration the coefficient $\beta$ is calculated, and its value is compared to a threshold to verify if the expected value is sufficiently stabilized. The Monte Carlo ends when $\beta$ is lower than the threshold. In this case, the function F is the annual $PLD_{average}$ and a threshold of 1% was used. Table 5.22 presents the comparison between prices coming from the VRM simulation in scenario no. 4 and actual prices from the Brazilian electricity market.

**Table 5.22 – Resulting prices from the simulation (VRM) versus actual data (Brazil)**

| Year | Data | monthly *PLD* (R$) | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | $PLD_{average}$ | σ | N | β |
| 2012 | VRM | 2 | 3 | 11 | 31 | 46 | 18 | 27 | 60 | 127 | 246 | 230 | 115 | 76,3 | 7,0 | 85 | 0,99% |
| | Brazil | 18 | 32 | 117 | 188 | 181 | 119 | 91 | 119 | 183 | 288 | 376 | 256 | 164,0 | - | | |
| | VRM/Brazil (%) | 11% | 9% | 9% | 16% | 25% | 15% | 30% | 50% | 69% | 85% | 61% | 45% | 47% | - | | |
| 2013 | VRM | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 59 | 126 | 139 | 228 | 68 | 89,3 | 5,0 | 32 | 0,99% |
| | Brazil | 412 | 214 | 340 | 196 | 345 | 207 | 117 | 159 | 263 | 252 | 331 | 291 | 260,6 | - | | |
| | VRM/Brazil (%) | 25% | 24% | 23% | 23% | 26% | 27% | 24% | 37% | 48% | 55% | 69% | 23% | 34% | - | | |
| 2014 | VRM | 82 | 242 | 216 | 215 | 215 | 116 | 191 | 371 | 394 | 467 | 477 | 212 | 266,5 | 16,3 | 39 | 0,98% |
| | Brazil | 375 | 714 | 775 | 758 | 680 | 361 | 570 | 710 | 729 | 766 | 805 | 601 | 653,6 | - | | |
| | VRM/Brazil (%) | 22% | 34% | 28% | 28% | 32% | 32% | 34% | 52% | 54% | 61% | 59% | 35% | 41% | - | | |

The data coming from this Monte-Carlo sample is provided in Appendix D. The monthly *PLD* value from the simulation of the VRM presented in this table is the monthly mean of all monthly data of this sample. The $PLD_{average}$ from the VRM data is the annual mean of its respective monthly values.

We have found from the analysis provided in Sections 5.2.1 (year 2012), 5.2.2 (year 2013) and 5.2.3 (year 2014) that the short-term prices (*PLD*) in scenario no. 4 are lower than the actual data of the Brazilian electricity market. After runing several simulations until the value of $\beta$ is lower than 1% (total of 85 simulations for 2012, 32 for 2013, and 39 for 2014), the previous conclusion is confirmed: prices indeed decrease with the implementation of the VRM.

Furthermore, we notice prices significantly lower compared to the current model. The VRM annual $PLD_{average}$ of the three years are about 60% lower than the corresponding data from Brazil, and the standard deviations ($\sigma$) of these values are 10% lower than their mean value (e.g. in 2014 16,3 represents 6% of the mean 266,5). In addition, the VRM monthly values are also notable lower: about 70% lower in the two trimester of the year, and 50% lower in the last trimester. All these values were obtained with a relative uncertainty, or coefficient of variation, $\beta$, very small (lower than 1%).

# Chapter 6 – Conclusions

As stated in Chapter 1, this research aimed to develop a new market design, the Virtual Reservoir Model (VRM), in which the ISO operates the power system from a physical point of view, while agents have more flexibility to manage their commercial commitments in the virtual commercial environment. At the end of the day, two worlds would coexist: the real one, associated with the power system and with physical effects; and the virtual one, related to the settlement system and with commercial effects. Through the VRM, hydro agents use their bids to financially back their contracts and then adjust their positions in the short-term.

Regarding Brazil, the VRM is an alternative to improve the short-term market (where the differences between the contracted energy and the amount of electricity generated / consumed are calculated and settled), and it is in line with the existing bilateral contract markets, both the Regulated Contracting Environment – *ACR* and the Free Contracting Environment – *ACL*. Nevertheless, the implementation of the VRM implies the replacement of the physical guarantee's seasonalization and the *MRE* (mechanism to share risk between the hydros) by the Energy Right Account (ERA) scheme.

Through the VRM, the price in Brazil would no longer primarily result from a chain of computational models that may eventually present problems related to inconsistencies and transparency, but it is obtained through the combination of thermal costs originated from the ISO dispatch and the short-term price arising from the liberalized hydro short-term market. To simulate the behavior of the Brazilian hydros in this market design, an Agent-Based Model with the reinforcement Q-Learning algorithm was developed. The agents prepare their bids aiming at (i) avoiding negative exposures in case of ending up providing successful bids lower than bilateral contracts and (ii) geting extra profit in the short-term market when there is more energy than the amount required to comply with the ex-ante contracts.

The Research Question presented in the first chapter was:

- Having in mind hydrothermal systems with a large share of hydros with multiple owners in the cascades, how will the electricity market based on bids and virtual reservoirs operate, and how should it be designed to enhance the flexibility of market participants to comply with their contracts while ensuring the same levels of security of supply and efficiency in the use of energy resources?

After validating the algorithm, several simulations of the Brazilian electricity market (embracing the last three years and with data representing more than 98% of the total hydro installed capacity of the country) were performed, and the main findings that answer the above Research Question are provided below.

## 6.1 Main findings

The results indicate that the proposed market design maintains the current efficiency and security levels , while enhancing the level of flexibility regarding the commercial behavior of the agents. As a consequence, the management of (virtual) reservoirs is the responsibility of each hydro, which could (virtually) save water according to their own risk perception. In doing so, the operation of the physical system is not affected, ensuring the efficiency in the hydro cascade and maintaining the current level of the security of supply.

The proposed VRM operates as a market based on bids. So, notably this market design contains an increased degree of freedom when compared to the rules of the seasonalization of the physical guarantee (namely regarding its annual "window" for the monthly allocation) and the *MRE* (where energies are automatically shared). By replacing the *MRE* and the seasonalization process by the VRM, there is an increase in the level of flexibility regarding the commercial behavior of the agents.

A comparison between the VRM and the *MRE* can be done as follows. In both schemes there is a kind of sharing arrangement among hydros. However, whereas in the *MRE* the power generated is shared, in the VRM it is shared the natural affluent energy that arrives in the system (in the simulation, it was represented by the acronym NAE). The NAE is the main input resource to produce electricity. So, the VRM shares an input of the system (water), while the *MRE* shares its output (electricity). Consequently, the VRM allows a greater management of bilateral contracts since who decides the output (even being a virtual output) are the generators themselves, not a third part (the ISO) who is not aware of their contracts. Finally, there is not an automatic distribution of the (output) resource to be shared (as it happens in the *MRE*). Instead of that, the (input) resource is used according to the perception of risk and under the commandment of a competitive market (once the VRM was design to do so).

The comparison between the virtual reservoirs resulting from the VRM simulation of the Brazilian market and the actual physical reservoir levels (Section 5.2.4.2) highlights the aforementioned statement. As evidenced in the Tucuruí case, it is possible to unlink two distinct interests: that one focused on the physical aspects of the power system, and the other one concerned to the compliance with signed contracts. Furthermore, both sides are acting to optimize their interests, and the link that binds these two worlds is the NAE. Conclusively, from the overall picture obtained in Section 5.2.4.3, we conclude that there is no change in the indicator GSF under the global point of view (i.e. the endured contracts remain essentially at the same level), while in the individual spheres there is an improvement since the VRM adds flexibility to sustain contracts (hydros are release from the *MRE's* straitjacket).

The results obtained also demonstrate that the final monthly short-term market prices (in Brazil, *PLD*) substantially decrease in comparison with the current price (*PLD*). As verified in Section 5.2.4.2, the new monthly prices are about 70% lower in the two trimesters of the simulated years, and 50% lower in the last trimester. Considering the last three years (2012, 2013 and 2014), in annual bases and with a relative uncertainty $\beta$ lower than 1%, new prices are 60% lower. This represents astonished very relevant finding, and positive affects could then be observed in the market.

Chapter 3 presented the main aspects of the Brazilian power system and its electricity market. In a few words, an important rule to be appropriately summarized here is the following: the electricity demand of both distribution utilities (on behalf of captive consumers) and free consumers must ensure the compliance of 100% of their consumptions by energy and power purchased through bilateral contracts, which must be registered at the market operator

(Decree 5163/2004, art 2º, items II and III). As a result, this legal provision definitely imposes a bottleneck on the trading of electricity in the short-term market.

So, generation companies tend to sign bilateral contracts and recover their cost (fixed and variable costs). In the short-term there is the accounting and settlement of differences between the contracted and the delivered energy. On balance, when companies don't deliver the quantity needed to comply with their contracts, they have to buy the difference in the short-term market at *PLD*. By definition, during 2012, 2013 and 3014 the *PLD* varies between the maximum value between cost of the last non-hydro dispatched resource ($PLD_{nh}$) and the minimum regulatory price (when there wasn't any dispatched thermal power plant).

In the last part of section 3.3.3 it was reported that Brazil nowadays faces a situation characterized by hydros with their physical guarantee extensively committed though contracts, a widespread water shortage across the country, a large thermal dispatch, a sharply decrease of hydro production, and sky-rocketing short-term market prices. Indeed, the *MLT* values for 2012, 2013 and 2014 presented in the previous chapter endorse this condition. It was also indicated that nowadays hydro generators are facing losses of billions of Reais (R$) due the exposure to high *PLD*s.

With the implementation of the VRM, the *PLD* shall be calculated by the weighted average considering the most expensive successful hydro price bid and the variable cost of the last non-hydro resource dispatched by the ISO (equation 4.6 in Chapter 4). In scenario no. 4 the ceiling price is equal to the variable cost of the last non-hydro station dispatched (PLDnh). So, considering equation 4.6, if the price from the hydro virtual short-term market (PLDh) is equal to the ceiling price (PLDnh), the final price (*PLD*) ends up equal to the ceiling price (PLDnh). In this case, the final price in both the current market and the VRM will be the same.

In other words, the results from the simulation could show a *PLD* equal to the ceiling price. However, instead of that the results show monthly *PLD*s equal to, at maximum, 50% of the ceiling price. In annual basis, the average *PLD* is 60% lower than the current annual average *PLD*. This can be explained by the presence of two elements: competition among hydros to endure bilateral contracts and contracting scheme where loads must be fully ex-ante contracted. Both elements are linked. The contracting scheme pushes hydros to sign bilateral contracts and, later on, competition in short-term market forces them to bid at lower prices to be succeeded in delivering the contracted energy.

After all, the *PLD* goes down driven by natural market forces. During the years of water scarcity, this decrease of *PLD* creates a financial relief in accounts of hydros companies that have to buy electricity to recompose their exposed positions. In contrast, in good hydrological years, when there is more energy than necessary to comply with contracts, the decrease in prices will limit the gains of the hydros, which appears to be quite reasonable given the mitigation of losses in bad years. As we can conclude, the VRM could also be seen as a tool to deal with the financial crises that hydros companies are facing nowadays in Brazil.

Lastly, by the creation of the VRM and, consequently, its centralized trading mechanism, it is expected to foster the transition of the current Brazilian market towards a more mature and efficient market, and then to enhance the economic stability of the new market. This can be achieved by promoting several aspects of the market:

- Standardized products: the VRM offers standard products for short-term agreements, e.g. it can be a day-ahead or a week-head market as a sequence of call markets for every delivery period, and where agents submit bids as a standardized product;
- Transparency: the rules which govern the market are publicly known, available to all market participants and applied on the same way whatever the market participants;
- Liquidity: since the market will enable participants to submit their orders quickly, each participant can close out an open position when it is no longer attractive; and
- Confidence: the price of the hydro market is influenced by the interaction among market participants and, thus, the whole sector can assess valuable price information . In addition, this market is designed to operate as an organized market managed by a power exchange working closely to the regulator to provide market surveillance in order to monitor and assess its operation.

## 6.2 Final considerations

This section is dedicated to comment some pertinent questions regarding the design of the VRM, the implementation of the Q-learning algorithm, and thoughts about the simulation of the Brazilian electricity market suggested by the developed work.

First of all, it must be said that the VRM was conceived and tested as a monthly-ahead market because Brazil nowadays has a settlement process carried on by the market operator on monthly basis. Nevertheless, the VRM can also be implemented as a day-ahead market. To do so, the deposit (DEP) in the energy right accounts (ERAs) must be done on a daily basis. In addition, the implementation of such short-term market can be seen as a final step of the whole process that the market will eventually undergo in the next years. A day-ahead market with hourly prices would then contribute to create a short-term price closer to the generation operation of the power system and with characteristics that better foster the demand response.

Regarding the learning algorithm, as can be noted in Section 4.5.2 (Table 4.3), the Q-learning matrix includes a discrete set of actions. For instance, for BID2 the discretization of bids are divided at intervals of 20% of the quantity bid (qBID) and 25% of the price bid (pBID). In other words, the set of actions is limited by values of qBID equal to 0%, 20%, 40%, 60%, 80% and 100% of the available energy, and by values of pBID equal to 0%, 25%, 50%, 75% and 100% of the ceiling price. So, an increase in the number of possible actions (and the consequent adoption of smaller intervals in qBID and pBID) can be seen as an improvement of the algorithm. Nevertheless, with the current 27 possible actions for BID2, the Q-learning matrix and the simulation of 155 hydropower plants, the algorithm takes around 10 minutes to converge.

An increase in the number of possible actions dramatically increases the processing time. It is estimated that if the interval of possible actions for BID2 decrease to 5% of the available energy (for qBID) and 5% of the ceiling price (for pBID), the algorithm will take more than 3 hours to converge. If the gap between two adjacent quantity and price bids decrease to 1%, one single simulation of the Brazilian electricity market could take more than 2,5 days. The current set of 27 actions was chosen in order to turn the use of the algorithm manageable considering both the processing time and the quality of the results.

With respect to the Brazilian electricity market, some questions may still be commented to enhance the sensitiveness of the performed simulations. In real life, each agent can perform a different seasonalization of the ex-ante contracts. Nevertheless, it is expected that, as it was simulated in scenario no. 4, all hydros adopt to a great extent a seasonalization that follows the pattern of the natural energy affluent (NAE).

Each agent can also choose a different level of qCE, which means that they can commit distinct percentages of their physical guarantee to bilateral contracts. The simulations of the VRM in Brazil in scenario no. 4 used a level equal to 95% for all hydros. Despite some abridgement, we consider that this value is quite consistent with what the companies adopted in the years 2012, 2013 and 2014.

Finally, in the VRM each agent can manage his reservoir according to his own risk perception. Thus, he can use a variety of target reservoir levels for the last month of the period. The simulations performed for the Brazilian electricity market implemented a single target for all reservoirs: to end the year with 25% of his capacity. This value proved to be very coherent with the weather patterns of the last three years and, as it can be verified by the results presented in Appendix C (Comparison between the actual and the virtual reservoir levels), it is very close to what the ISO has adopted to operate the power system.

## 6.3 Future works

Considering the VRM market design and the algorithm developed in this thesis, some future works can be carried on both to expand the scope of analysis and to go deeper in a particular issue. For instance, the algorithm can be reviewed to run simulations taking into account that the strategy must be learned by an holding entity having a portfolio of power stations, which will enlarge the outlook of the problem from the single project point of view to the company that owns several hydros. By doing so, it would be possible to analyse the exercise of market power and its influence in price.

In this thesis it was considered the uniform price procedure, not the pay-as-bid one. Thus, the rules implemented in the algorithm to execute the financial settlement of the bids can be modified to allow the pay-as-bid procedure. In this case, the equation of the final short-term market price must be adapted. Instead of the weighted average considering the clearing price from the VRM and the variable cost of the last non-hydro resource dispatched by the ISO, it can be used the weighted average of each successful bid into the VRM and each non-hydro resource dispatched by the ISO.

Furthermore, simulations can be extended to produce zonal short-term prices (the present research was done bearing in mind the Brazilian electricity market with a single zonal price). For instance, the algorithm can be adapted to calculate four zonal prices, each one according to the current definition of the Brazilian submarkets: North (*N*), Northeast (*NE*), Southeast-Midwest (*SE-CO*) and South (*S*).

Nowadays in Brazil most of the hydros have the capacity to store water for one year. Nevertheless, there are some exceptions: those with very large reservoirs where water can be stored for two, three and four years ahead. Therefore, for these cases the algorithm can be upgraded to allow the representation of a multi-annual reservoir. Strictly speaking, as they have more stored capacity, their management of the reservoir can be different, altering the reservoir level target at the end of each month.

In addition, there are two special concerns related to the sustainability of the energy system by which, from the framework of the VRM developed so far, future works can also be done. These concerns are the following: large scale implementation of distributed renewable generations and use of more efficient energy demand side management.

Distributed renewable generation sources and demand side management will create new opportunities associated with the renewal of the value preposition of the consumers, followed by the renewal of the profit model of the companies. However, it is crucial to have a proper market to support this change in order to allow the players to organize themselves to develop new business models. It is recognized that price is the connective element between the market participants, both consumers and producers. This economical signal is one of the main outputs of the simulations developed in this work. The new short-term price profile that will come from the VRM, as previously mentioned, can be further designed to have an hourly basis, which gets closer to the generation operation cost.

By using an hourly price profile, which drastically differs from the current practice in Brazil (calculated on a weekly-ahead basis for three load periods), the overlap between peak hour prices and periods with large production can encourage the installation of PV panels and increase the profitability of this business. So, the new price profile emerging from a VRM operating as a day-ahead market can attract investments by itself. If that does not occur, this would mean that prices are not sufficiently attractive, and then different measures should be adopted such as subsidies or specific public auctions where only solar generation can participate and compete against each other to sell an amount of energy to the distribution or retailing companies.

This analysis on the changes affecting the price profile can also be applied to other electricity sources. For example, from the emerging VRM price profile, it can be interesting to study the case of wind power with emphasis on the wind forecast and electricity production in wind parks distributed by different areas of Brazil in order to identify the most promising locations considering the price and the production profiles, or to combine them with storage technologies, as for instance a wind farm and a pumping hydro power plant with reservoir.

Lastly, regarding the energy demand side management, taking into account a VRM running with both the supply and demand curves meet on an hourly basis, it is possible to test different slopes of the demand curve. In this analysis, each slope can represent a particular demand reaction towards the price. So, different elasticities of the demand to the price can be tested just adjusting the slope of the demand curve in order to investigate how it interacts with the market prices.

When running the model with a shed light on the policies to induce energy savings, it is possible to find which measure is more effective in decreasing price, and how much price can be reduced. This sensitivity analysis provides useful insights to particular consumers, when selecting a specific measure, or to governmental agencies, when designing new legal or regulatory mechanisms. We therefore hope that the models and the insights provided by this reaserch can be of use in Brazil and can contribute to efficiently use resources, while providing reduction of the short-term market price.

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# Appendix A – Data regarding the Brazilian hydropower plants used in the simulation

| # | Name of the hydro | Start of operation (connection to SIN) | With reservoir (wr) or run-of-the-river (rr) | Geographic area of NAEs influence | Submarket | IC - Installed Capacity (MW) | PG - Physical Guarantee (MWaverage) | RC – Reservoir Capacity (MWmonth) | Reservoir level in jan/2014 (%) | Reservoir level in jan/2013 (%) | Reservoir level in jan/2012 (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Tucuruí | 1984 | wr | N | N | 8,370.0 | 4,140.0 | 7,631.8 | 44.23 | 25.35 | 35.73 |
| 2 | Ilha Solteira | 1993 | wr | SE-CO | SE-CO | 4,252 | 1,949.0 | 5,591.9 | 57.33 | 45.83 | 57.94 |
| 3 | Itumbiara | 1980 | wr | SE-CO | SE-CO | 2,082 | 1,015.0 | 15,917.0 | 37.21 | 10.01 | 36.03 |
| 4 | São Simão | 1978 | wr | SE-CO | SE-CO | 1,710 | 1,281.0 | 5,125.4 | 29.69 | 28.51 | 74.50 |
| 5 | Gov, Bento Munhoz | 1980 | wr | S | S | 1,676 | 576.0 | 6,038.9 | 39.71 | 19.02 | 55.58 |
| 6 | Luiz Gonzaga (Itaparica) | 1988 | wr | NE | NE | 1,480 | 959.0 | 3,433.9 | 42.02 | 41.05 | 54.89 |
| 7 | Marimbondo | 1975 | wr | SE-CO | SE-CO | 1,440 | 726.0 | 5,494.1 | 38.86 | 16.13 | 34.60 |
| 8 | Salto Santiago | 1980 | wr | S | S | 1,420 | 703.3 | 3,239.2 | 68.08 | 16.32 | 72.96 |
| 9 | Água Vermelha | 1978 | wr | SE-CO | SE-CO | 1,396 | 746.0 | 4,482,5 | 41.51 | 15.96 | 48.58 |
| 10 | Serra da Mesa | 1998 | wr | N | N | 1,275 | 671.0 | 35,112.7 | 31.34 | 39.68 | 50.00 |
| 11 | Gov, Ney Braga (Segredo) | 1992 | wr | S | S | 1,260 | 603.0 | 455.6 | 49.86 | 61.68 | 75.91 |
| 12 | Furnas | 1963 | wr | SE-CO | SE-CO | 1,216 | 598.0 | 35,228.2 | 49.89 | 12.35 | 71.44 |
| 13 | Emborcação | 1982 | wr | SE-CO | SE-CO | 1,192 | 497,0 | 21,834.5 | 37.92 | 35.03 | 63.76 |
| 14 | Machadinho | 2002 | wr | S | S | 1,140 | 529,0 | 916.3 | 39.69 | 16.60 | 28.95 |
| 15 | Sobradinho | 1979 | wr | NE | NE | 1,050 | 531,0 | 30,183.5 | 33.04 | 27.35 | 46.88 |
| 16 | Henry Borden (Billings) | 1926 | wr | SE-CO | SE-CO | 889 | 127.7 | 2,506.7 | 68.37 | 63.85 | 65.68 |
| 17 | Campos Novos | 2007 | wr | S | S | 880 | 377.9 | 232.7 | 43.00 | 69.60 | 36.00 |
| 18 | Três Irmãos | 1993 | wr | SE-CO | SE-CO | 807.5 | 217.5 | 624.0 | 58.27 | 55.41 | 54.80 |
| 19 | Barra Grande | 2005 | wr | S | S | 708 | 380.6 | 3,023.2 | 48.12 | 37.17 | 32.75 |
| 20 | Capivara | 1977 | wr | SE-CO | SE-CO | 619 | 330.0 | 3,981.3 | 80.37 | 28.39 | 76.26 |
| 21 | Nova Ponte | 1994 | wr | SE-CO | SE-CO | 510 | 276.0 | 22,976.8 | 35.81 | 28.83 | 62.21 |
| 22 | Peixe Angical | 2006 | wr | N | N | 498.8 | 280.0 | 113.7 | 80.80 | 55.53 | 69.33 |
| 23 | Mascarenhas de Moraes | 1956 | wr | SE-CO | SE-CO | 476 | 295.0 | 4,404.7 | 87.59 | 75.66 | 82.12 |
| 24 | Chavantes | 1970 | wr | SE-CO | SE-CO | 414 | 172.0 | 3,320.3 | 53.17 | 27.47 | 61.29 |
| 25 | Miranda | 1998 | wr | SE-CO | SE-CO | 408 | 202.0 | 270.9 | 67.41 | 61.33 | 69.79 |
| 26 | Três Marias | 1962 | wr | SE-CO | SE-CO | 396 | 239.0 | 2,314.9 | 29.72 | 39.20 | 78.19 |
| 27 | Corumbá I | 1997 | wr | SE-CO | SE-CO | 375.3 | 209.0 | 1,541.0 | 83.82 | 24.70 | 77.24 |
| 28 | Mauá | 2012 | wr | SE-CO | SE-CO | 361 | 197.7 | 255.0 | 26.24 | 51.99 | - |
| 29 | Irapé | 2006 | wr | SE-CO | SE-CO | 360 | 206.3 | 2,037.8 | 86.04 | 48.41 | 86.79 |
| 30 | Promissão | 1975 | wr | SE-CO | SE-CO | 264 | 104.0 | 1,848.3 | 40.12 | 47.75 | 33.72 |
| 31 | Gov, Parigot de Souza (Capivari/ Cachoeira) | 1970 | wr | S | S | 260 | 109.0 | 385.1 | 80.37 | 28.39 | 76.26 |
| 32 | Balbina | 2014 | wr | N | N | 250 | 110.0 | 544.7 | 47.88 | - | - |
| 33 | Boa Esperança (Castelo Branco) | 1970 | wr | NE | NE | 237.3 | 143.0 | 264.0 | 45.07 | 67.14 | 35.52 |
| 34 | Passo Fundo | 1973 | wr | S | S | 226 | 115.5 | 1,733.3 | 97.55 | 58.60 | 70.06 |

| # | Name of the hydro | Start of operation (connection to SIN) | With reservoir (wr) or run-of-the-river (rr) | Geographic area of NAEs influence | Submarket | IC - Installed Capacity (MW) | PG - Physical Guarantee (MWaverage) | RC – Reservoir Capacity (MWmonth) | Reservoir level in jan/2014 (%) | Reservoir level in jan/2013 (%) | Reservoir level in jan/2012 (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 35 | Samuel | 1989 | wr | N | SE-CO | 216.8 | 85.2 | 252.3 | 43.72 | 0.00 | 7.11 |
| 36 | Funil - Furnas | 1969 | wr | SE-CO | SE-CO | 216 | 121.0 | 793.6 | 49.10 | 46.03 | 39.23 |
| 37 | Serra do Facão | 2010 | wr | SE-CO | SE-CO | 212.6 | 182.4 | 6,613.4 | 53.87 | 30.76 | 84.61 |
| 38 | Passo Real | 1973 | wr | S | S | 158 | 68.0 | 2,984.9 | 84.25 | 75.29 | 71.36 |
| 39 | Barra Bonita | 1963 | wr | SE-CO | SE-CO | 140.8 | 45.0 | 2,748.0 | 78.93 | 67.70 | 49.42 |
| 40 | Corumbá IV | 2006 | wr | SE-CO | SE-CO | 129.6 | 76.0 | 1,710.4 | 14.14 | 21.89 | 16.38 |
| 41 | Santa Clara | 2005 | wr | S | S | 120 | 69.6 | 367.5 | 61.42 | 88.26 | 50.34 |
| 42 | Quebra Queixo | 2003 | wr | S | S | 120 | 59.7 | 10.1 | 77.37 | 84.98 | 93.02 |
| 43 | Porto Estrela | 2001 | wr | SE-CO | SE-CO | 112 | 55.8 | 12.6 | 100.00 | 72.00 | 94.44 |
| 44 | Queimado | 2004 | wr | SE-CO | SE-CO | 105 | 58.0 | 277.0 | 56.60 | 31.21 | 65.04 |
| 45 | Jurumirim | 1962 | wr | SE-CO | SE-CO | 101 | 47.0 | 4,070.0 | 68.51 | 30.49 | 66.71 |
| 46 | Corumbá III | 2009 | wr | SE-CO | SE-CO | 95.5 | 50.9 | 423.4 | 30.85 | 26.55 | 10.07 |
| 47 | Barra dos Coqueiros | 2010 | wr | SE-CO | SE-CO | 90 | 57.3 | 43.5 | 23.49 | - | - |
| 48 | Paraibuna | 1978 | wr | SE-CO | SE-CO | 85 | 50.0 | 4,459.2 | 50.20 | 36.48 | 67.45 |
| 49 | Caconde | 1966 | wr | SE-CO | SE-CO | 80.4 | 33.0 | 857.6 | 54.18 | 39.24 | 61.73 |
| 50 | Caçu | 2010 | wr | SE-CO | SE-CO | 65 | 42.9 | 34.5 | 28.48 | - | - |
| 51 | Camargos | 1960 | wr | SE-CO | SE-CO | 46 | 21.0 | 1,571.4 | 25.98 | 31.21 | 54.00 |
| 52 | Espora | 2006 | wr | SE-CO | SE-CO | 32 | 23.5 | 116.1 | 28.56 | 16.94 | 19.69 |
| 53 | Jaguari | 1973 | wr | SE-CO | SE-CO | 27.6 | 14.0 | 1,183.3 | 51.05 | 47.60 | 84.19 |
| 54 | Jordão | 1997 | wr | S | S | 6.5 | 5.9 | 19.7 | 26.38 | 71.31 | 50.12 |
| 55 | Ernestina | 1950 | wr | S | S | 5 | 3.2 | 211.2 | 92.42 | 81.81 | 26.32 |
| 56 | Itaipú | 1989 | rr | SE-CO | SE-CO | 14,000 | 8,182.0 | - | - | - | - |
| 57 | Complexo Paulo Afonso | 1979 | rr | NE | NE | 4,279.6 | 2,225.0 | - | - | - | - |
| 58 | Jirau | 2013 | rr | N | SE-CO | 3,750 | 2,184.6 | - | - | - | - |
| 59 | Xingó | 1994 | rr | NE | NE | 3,162 | 2,139.0 | - | - | - | - |
| 60 | Santo Antônio | 2012 | rr | N | SE-CO | 3,150.4 | 2,218.0 | - | - | - | - |
| 61 | Jupiá | 1969 | rr | SE-CO | SE-CO | 1,551.2 | 886.0 | - | - | - | - |
| 62 | Porto Primavera | 1999 | rr | SE-CO | SE-CO | 1,540 | 1,017.0 | - | - | - | - |
| 63 | Itá | 2000 | rr | S | S | 1,450 | 969.9 | - | - | - | - |
| 64 | Gov, José Richa | 1999 | rr | S | S | 1,240 | 605.0 | - | - | - | - |
| 65 | Salto Osório | 1975 | rr | S | S | 1,078 | 507.3 | - | - | - | - |
| 66 | Estreito (Luiz Carlos Barreto de Carvalho) | 1969 | rr | SE-CO | SE-CO | 1,048 | 495.0 | - | - | - | - |
| 67 | Luis Eduardo Magalhães (Lajeado) | 1998 | rr | N | N | 902.5 | 527.0 | - | - | - | - |
| 68 | Foz do Chapecó | 2010 | rr | S | S | 855 | 432.0 | - | - | - | - |
| 69 | Cachoeira Dourada | 1958 | rr | SE-CO | SE-CO | 658 | 415.0 | - | - | - | - |
| 70 | Taquaruçu | 1992 | rr | SE-CO | SE-CO | 525 | 201.0 | - | - | - | - |
| 71 | Itaúba | 1978 | rr | S | S | 500 | 190.0 | - | - | - | - |

| # | Name of the hydro | Start of operation (connection to SIN) | With reservoir (wr) or run-of-the-river (rr) | Geographic area of NAEs influence | Submarket | IC - Installed Capacity (MW) | PG - Physical Guarantee (MWaverage) | RC – Reservoir Capacity (MWmonth) | Reservoir level in jan/2014 (%) | Reservoir level in jan/2013 (%) | Reservoir level in jan/2012 (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 72 | Itapebi | 2003 | rr | NE | NE | 462 | 214.3 | - | - | - | - |
| 73 | Cana Brava | 2002 | rr | N | N | 450 | 264.6 | - | - | - | - |
| 74 | Estreito | 2011 | rr | N | N | 435.6 | 235.2 | - | - | - | - |
| 75 | Jaguara | 1971 | rr | SE-CO | SE-CO | 424 | 336.0 | - | - | - | - |
| 76 | Nilo Peçanha | 1953 | rr | SE-CO | SE-CO | 380 | 335.0 | - | - | - | - |
| 77 | Volta grande | 1974 | rr | SE-CO | SE-CO | 380 | 229.0 | - | - | - | - |
| 78 | Rosana | 1987 | rr | SE-CO | SE-CO | 354 | 177.0 | - | - | - | - |
| 79 | Nova Avanhandava | 1982 | rr | SE-CO | SE-CO | 347.4 | 139.0 | - | - | - | - |
| 80 | Simplicio | 2013 | rr | SE-CO | SE-CO | 333.7 | 191.3 | - | - | - | - |
| 81 | Aimorés | 2005 | rr | SE-CO | SE-CO | 330 | 172.0 | - | - | - | - |
| 82 | Porto Colômbia | 1973 | rr | SE-CO | SE-CO | 319.2 | 185.0 | - | - | - | - |
| 83 | Dardanelos | 2011 | rr | N | SE-CO | 261 | 154.9 | - | - | - | - |
| 84 | São Salvador | 2009 | rr | N | N | 243.2 | 141.6 | - | - | - | - |
| 85 | Amador Aguiar I | 2006 | rr | SE-CO | SE-CO | 240 | 155.0 | - | - | - | - |
| 86 | Funil - Cemig | 2002 | rr | SE-CO | SE-CO | 216 | 121.0 | - | - | - | - |
| 87 | Funil - Chesf | 1962 | rr | NE | NE | 216 | 121.0 | - | - | - | - |
| 88 | Igarapava | 1999 | rr | SE-CO | SE-CO | 210 | 136.0 | - | - | - | - |
| 89 | Amador Aguiar II | 2007 | rr | SE-CO | SE-CO | 210 | 131.0 | - | - | - | - |
| 90 | Mascarenhas | 1974 | rr | SE-CO | SE-CO | 193.5 | 134.7 | - | - | - | - |
| 91 | Garibaldi | 2013 | rr | S | S | 191.9 | 83.1 | - | - | - | - |
| 92 | Ilha dos Pombos | 1924 | rr | SE-CO | SE-CO | 187.2 | 115.0 | - | - | - | - |
| 93 | Jacuí | 1962 | rr | S | S | 180 | 123.0 | - | - | - | - |
| 94 | Ponte de Pedra | 2005 | rr | SE-CO | SE-CO | 176.1 | 123.5 | - | - | - | - |
| 95 | Pedra do Cavalo | 2004 | rr | NE | NE | 160 | 56.4 | - | - | - | - |
| 96 | Bariri | 1965 | rr | SE-CO | SE-CO | 143.1 | 66.0 | - | - | - | - |
| 97 | Baguari | 2009 | rr | SE-CO | SE-CO | 140 | 80.2 | - | - | - | - |
| 98 | Gullman-Amorim | 1997 | rr | SE-CO | SE-CO | 140 | 65.9 | - | - | - | - |
| 99 | Risoleta Neves (Candonga) | 2004 | rr | SE-CO | SE-CO | 140 | 64.5 | - | - | - | - |
| 100 | Fontes Nova | 1940 | rr | SE-CO | SE-CO | 132 | 104.0 | - | - | - | - |
| 101 | Ibitinga | 1969 | rr | SE-CO | SE-CO | 131.5 | 74.0 | - | - | - | - |
| 102 | Castro Alves | 2008 | rr | S | S | 130 | 64.0 | - | - | - | - |
| 103 | Dona Francisca | 2001 | rr | S | S | 125 | 80.0 | - | - | - | - |
| 104 | Fundão | 2006 | rr | S | S | 120 | 65.8 | - | - | - | - |
| 105 | Guaporé | 2003 | rr | S | S | 120 | 60.2 | - | - | - | - |
| 106 | Salto | 2010 | rr | SE-CO | SE-CO | 116 | 67.8 | - | - | - | - |
| 107 | Salto | 2010 | rr | SE-CO | SE-CO | 116 | 63.8 | - | - | - | - |
| 108 | Euclides da Cunha | 1960 | rr | SE-CO | SE-CO | 108.8 | 49.0 | - | - | - | - |
| 109 | Salto Grande | 1956 | rr | SE-CO | SE-CO | 102 | 75.0 | - | - | - | - |
| 110 | Salto Grande | 1958 | rr | SE-CO | SE-CO | 102 | 75.0 | - | - | - | - |

| # | Name of the hydro | Start of operation (connection to SIN) | With reservoir (wr) or run-of-the-river (rr) | Geographic area of NAEs influence | Submarket | IC - Installed Capacity (MW) | PG - Physical Guarantee (MWaverage) | RC – Reservoir Capacity (MWmonth) | Reservoir level in jan/2014 (%) | Reservoir level in jan/2013 (%) | Reservoir level in jan/2012 (%) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 111 | 14 de Julho | 2008 | rr | S | S | 100 | 50.0 | - | - | - | - |
| 112 | Monte Claro | 2004 | rr | S | S | 100 | 59.0 | - | - | - | - |
| 113 | Pereira Passos | 1962 | rr | SE-CO | SE-CO | 99.9 | 51.0 | - | - | - | - |
| 114 | Salto Rio Verdinho | 2010 | rr | SE-CO | SE-CO | 93 | 58.2 | - | - | - | - |
| 115 | Canoas 1 | 1999 | rr | SE-CO | SE-CO | 82.5 | 57.0 | - | - | - | - |
| 116 | Sá Carvalho | 1951 | rr | SE-CO | SE-CO | 78 | 58.0 | - | - | - | - |
| 117 | Alzir Santos (Monjolinho) | 2009 | rr | S | S | 74 | 43.1 | - | - | - | - |
| 118 | Canoas 2 | 1999 | rr | SE-CO | SE-CO | 72 | 48.0 | - | - | - | - |
| 119 | Piraju | 2002 | rr | SE-CO | SE-CO | 70 | 42.5 | - | - | - | - |
| 120 | Eng, José Luiz Muller de Godoy Pereira | 2010 | rr | SE-CO | SE-CO | 68.4 | 41.0 | - | - | - | - |
| 121 | Sobragi | 1998 | rr | SE-CO | SE-CO | 60 | 38.0 | - | - | - | - |
| 122 | Itutinga | 1955 | rr | SE-CO | SE-CO | 52 | 28.0 | - | - | - | - |
| 123 | Picada | 2006 | rr | SE-CO | SE-CO | 50 | 27.0 | - | - | - | - |
| 124 | Ourinhos | 2005 | rr | SE-CO | SE-CO | 44 | 23.7 | - | - | - | - |
| 125 | Limoeiro (Armando Salles de Oliveira) | 1958 | rr | SE-CO | SE-CO | 32 | 15.0 | - | - | - | - |

# Appendix B – Data regarding the Brazilian electricity market used in the simulation

**Year 2012**

| | jan/12 | feb/12 | mar/12 | apr/12 | may/12 | jun/12 | jul/12 | aug/12 | sep/12 | oct/12 | nov/12 | dec/12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $Q_{total}$ (MWaverage) | 59,342 | 62,546 | 63,019 | 60,574 | 58,891 | 58,164 | 58,295 | 59,771 | 60,289 | 62,224 | 61,035 | 62,549 |
| $Q_{nh}$ (MWaverage) | 6,093 | 6,061 | 5,757 | 9,296 | 9,986 | 8,965 | 8,575 | 9,298 | 12,424 | 14,774 | 16,955 | 15,694 |
| $Q_h$ (MWaverage) | 53,249 | 56,485 | 57,262 | 51,278 | 48,905 | 49,199 | 49,720 | 50,473 | 47,865 | 47,450 | 44,080 | 46,855 |
| PLDnh_SIN (R$/MWh) | 18.03 | 31.62 | 117.05 | 188.45 | 180.66 | 118.53 | 91.24 | 119.07 | 183.12 | 287.61 | 375.54 | 256.41 |
| PLDreg_uplim (R$/MWh) | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 | 727.52 |
| $PG_{total}$ (MWaverage) | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 | 46,180.04 |
| PG_N (MWaverage) | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 | 7,717.52 |
| PG_NE (MWaverage) | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 |
| PG_SE-CO (MWaverage) | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 | 25,223.76 |
| PG_S (MWaverage) | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 | 6,850.07 |
| NAE_SIN (MWaverage) | 107,837.29 | 83,968.79 | 60,711.00 | 51,386.72 | 43,610.20 | 58,752.00 | 40,039.03 | 28,279.00 | 22,572.00 | 24,784.00 | 34,485.27 | 43,261.03 |
| NAE_N (MWaverage) | 11,493.97 | 14,208.24 | 13,470.00 | 9,312.43 | 4,855.26 | 2,879.00 | 2,073.65 | 1,279.00 | 1,065.00 | 1,139.00 | 2,322.73 | 4,924.45 |
| NAE_NE (MWaverage) | 17,452.23 | 15,452.90 | 6,639.00 | 6,392.93 | 3,628.26 | 3,286.00 | 2,564.55 | 2,115.00 | 1,843.00 | 1,443.00 | 4,595.87 | 6,958.13 |
| NAE_SE-CO (MWaverage) | 72,278.19 | 48,945.31 | 36,757.00 | 31,966.93 | 29,683.29 | 38,526.00 | 25,728.06 | 17,020.00 | 14,914.00 | 14,803.00 | 22,883.67 | 26,868.39 |
| NAE_S (MWaverage) | 6,612.90 | 5,362.34 | 3,845.00 | 3,714.43 | 5,443.39 | 14,061.00 | 9,672.77 | 7,865.00 | 4,750.00 | 7,399.00 | 4,683.00 | 4,510.06 |

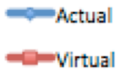
**Year 2013**

| | jan/13 | feb/13 | mar/13 | apr/13 | may/13 | jun/13 | jul/13 | aug/13 | sep/13 | oct/13 | nov/13 | dec/13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $Q_{total}$ (MWaverage) | 61,570 | 64,381 | 63,470 | 62,450 | 60,815 | 60,164 | 61,002 | 62,728 | 63,422 | 64,453 | 64,999 | 64,279 |
| $Q_{nh}$ (MWaverage) | 15,322 | 15,313 | 14,528 | 14,498 | 15,963 | 16,272 | 14,727 | 15,657 | 15,709 | 15,790 | 16,931 | 15,091 |
| $Q_{h}$ (MWaverage) | 46,248 | 49,068 | 48,942 | 47,952 | 44,852 | 43,892 | 46,275 | 47,071 | 47,714 | 48,663 | 48,068 | 49,188 |
| PLDnh_SIN (R$/MWh) | 411.86 | 213.57 | 339.69 | 196.44 | 344.87 | 206.83 | 116.71 | 159.25 | 263.18 | 251.91 | 331.07 | 291.01 |
| PLDreg_uplim (R$/MWh) | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 | 780.03 |
| $PG_{total}$ (MWaverage) | 48,639.04 | 48,639.04 | 48,639.04 | 48,639.04 | 48,639.04 | 48,639.04 | 48,639.04 | 48,639,04 | 48,639.04 | 48,639.04 | 48,639.04 | 48,639.04 |
| PG_N (MWaverage) | 9,902.12 | 9,902.12 | 9,902.12 | 9,902.12 | 9,902.12 | 9,902.12 | 9,902.12 | 9,902,12 | 9,902.12 | 9,902.12 | 9,902.12 | 9,902.12 |
| PG_NE (MWaverage) | 6,388.70 | 6,388.70 | 6,388.70 | 6,388,.0 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388,70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 |
| PG_SE-CO (MWaverage) | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415,06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 |
| PG_S (MWaverage) | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933,17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 |
| NAE_SIN (MWaverage) | 65,671.00 | 84,737.30 | 78,253.03 | 80,099.77 | 47,208.00 | 63,535,.4 | 51,457.00 | 40,750,96 | 37,126.84 | 40,891.78 | 34,151.20 | 59,941.00 |
| NAE_N (MWaverage) | 6,668.00 | 11,885.20 | 11,726.55 | 14,008.20 | 9,467.00 | 3,990.97 | 2,366.00 | 1,595,61 | 1,317.97 | 1,402.26 | 2,545.70 | 5,550.00 |
| NAE_NE (MWaverage) | 4,532.00 | 10,706.20 | 5,136.77 | 8,020.67 | 4,284.00 | 3,073.00 | 2,336.00 | 1,837,42 | 1,614.17 | 2,044.68 | 2,481.20 | 8,569.00 |
| NAE_SE-CO (MWaverage) | 45,513.00 | 55,199.50 | 48,811.29 | 50,500.67 | 28,561.00 | 37,856.57 | 31,001.00 | 19,340,90 | 17,109.87 | 23,846.65 | 22,480.13 | 39,281.00 |
| NAE_S (MWaverage) | 8,958.00 | 6,946.40 | 12,578.42 | 7,570.23 | 4,896.00 | 18,615.00 | 15,754.00 | 17,977,03 | 17,084.83 | 13,598.19 | 6,644.17 | 6,541.00 |

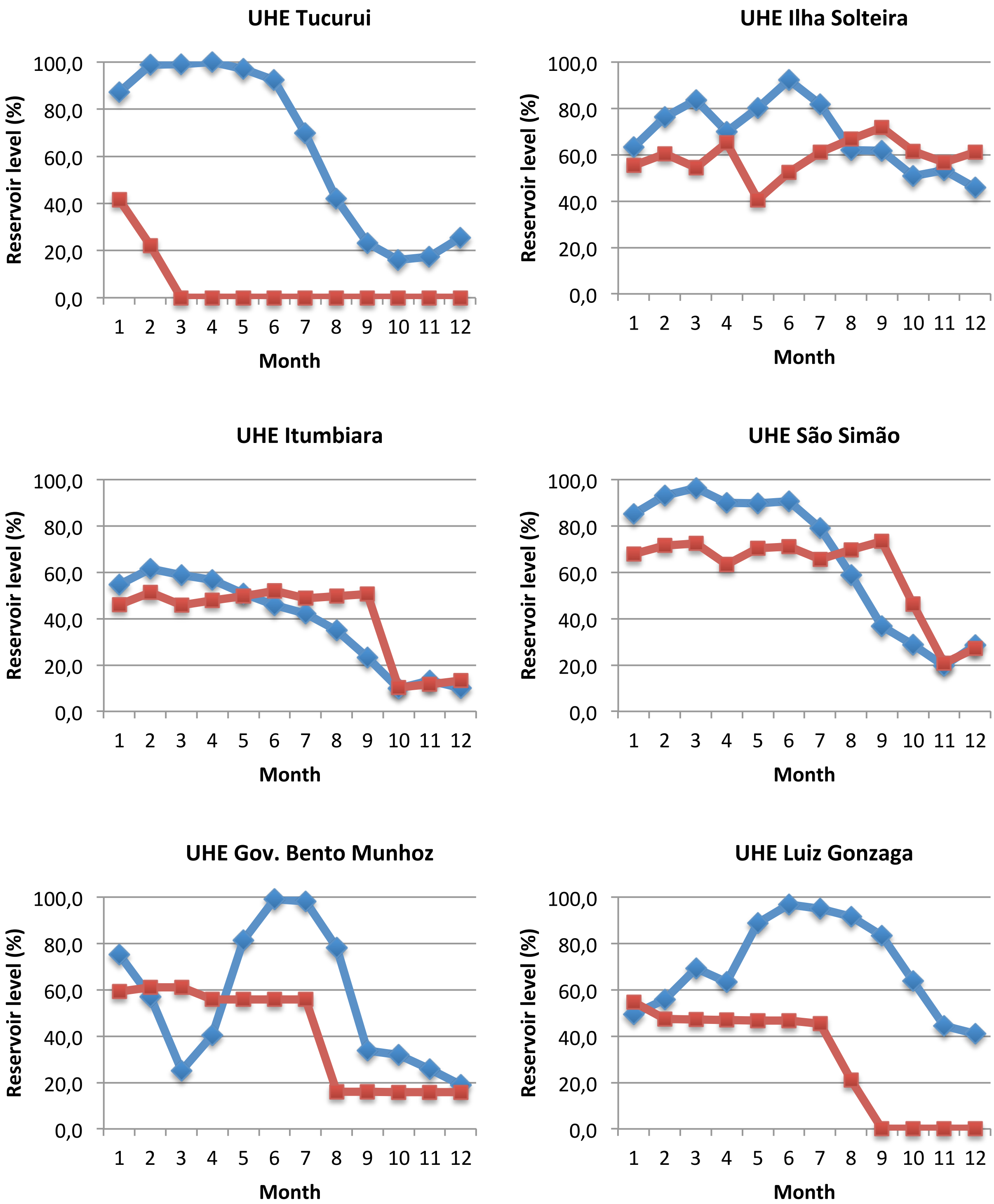
**Year 2014**

| | jan/14 | feb/14 | mar/14 | apr/14 | may/14 | jun/14 | jul/14 | aug/14 | sep/14 | oct/14 | nov/14 | dec/14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $Q_{total}$ (MWaverage) | 67,945 | 69,870 | 66,355 | 64,748 | 62,824 | 61,170 | 61,114 | 63,168 | 65,329 | 67,147 | 66,472 | 65,602 |
| $Q_{nh}$ (MWaverage) | 14,939 | 17,719 | 18,489 | 18,334 | 19,818 | 19,577 | 19,379 | 22,599 | 22,379 | 23,689 | 23,383 | 23,123 |
| $Q_h$ (MWaverage) | 53,006 | 52,151 | 47,866 | 46,414 | 43,006 | 41,593 | 41,735 | 40,569 | 42,950 | 43,458 | 43,089 | 42,479 |
| PLDnh_SIN (R$/MWh) | 375.15 | 713.50 | 774.56 | 757.67 | 680.19 | 361.21 | 570.18 | 709.53 | 728.95 | 765.54 | 804.54 | 601.21 |
| PLDreg_uplim (R$/MWh) | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 | 822.83 |
| $PG_{total}$ (MWaverage) | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 | 48,749.04 |
| PG_N (MWaverage) | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 | 10,012.12 |
| PG_NE (MWaverage) | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 | 6,388.70 |
| PG_SE-CO (MWaverage) | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 | 25,415.06 |
| PG_S (MWaverage) | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 | 6,933.17 |
| NAE_SIN (MWaverage) | 61,791.32 | 44,697.35 | 67,430.91 | 62,600.73 | 47,215.74 | 73,983.07 | 39,359.91 | 25,946.83 | 31,234.13 | 34,463.77 | 31,804.03 | 53,859.00 |
| NAE_N (MWaverage) | 10,084.03 | 12,974.14 | 17,435.32 | 15,403.73 | 9,748.84 | 4,182.87 | 2,364.23 | 1,561.32 | 1,261.23 | 1,435.42 | 2,294.30 | 4,709.00 |
| NAE_NE (MWaverage) | 11,008.35 | 3,971.29 | 3,830.65 | 4,712.33 | 2,999.94 | 2,040.60 | 1,851.42 | 1,906.06 | 1,627.47 | 1,230.06 | 2,250.17 | 6,625.00 |
| NAE_SE-CO (MWaverage) | 30,152.13 | 22,541.71 | 34,700.68 | 34,008.37 | 22,857.90 | 26,169.73 | 18,748.45 | 15,651.90 | 15,120.33 | 13,347.55 | 18,641.73 | 34,715.00 |
| NAE_S (MWaverage) | 10,546.81 | 5,210.21 | 11,464.26 | 8,476.30 | 11,609.06 | 41,589.87 | 16,395.81 | 6,827.55 | 13,225.10 | 18,450.74 | 8,617.83 | 7,810.00 |

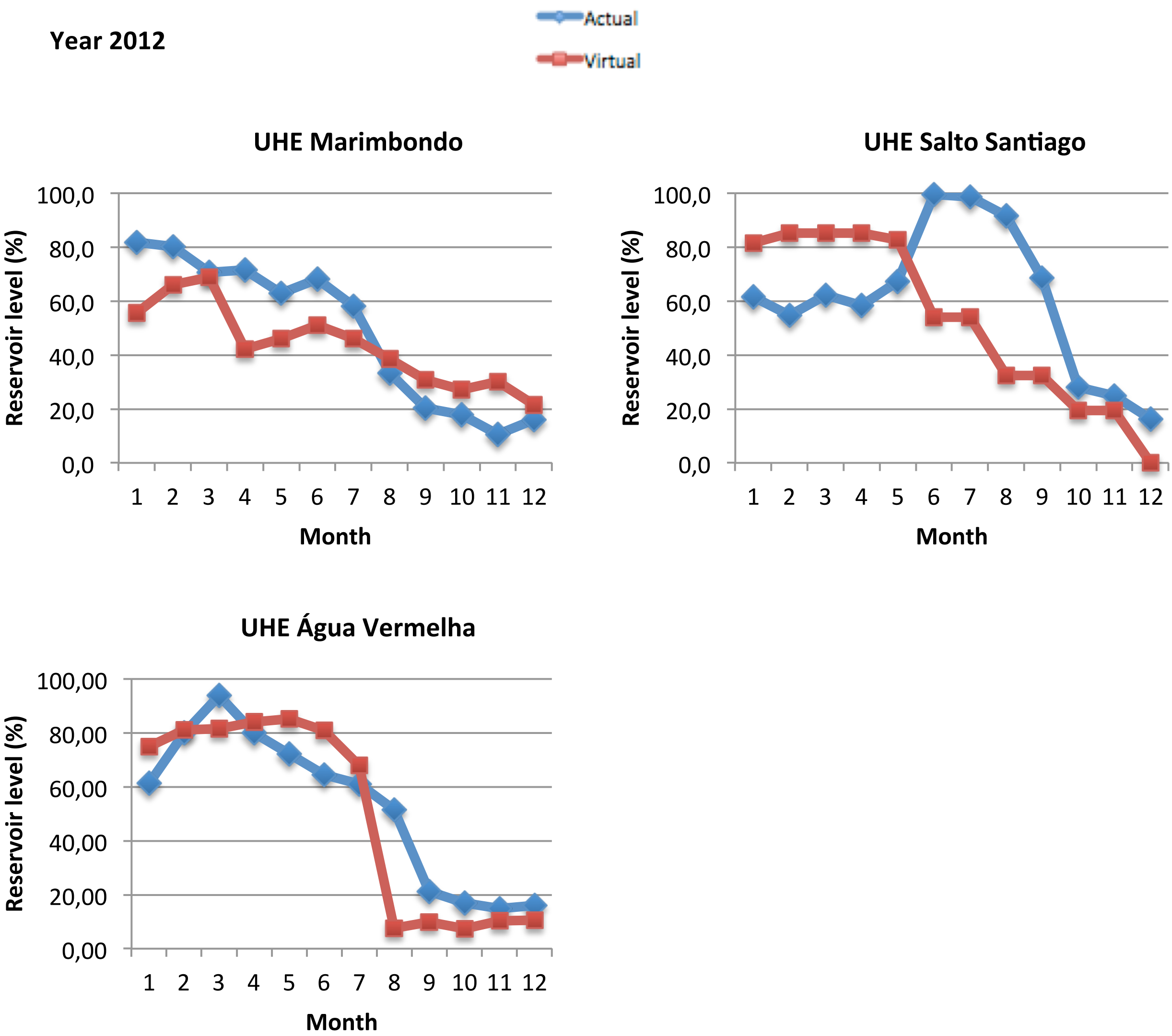
# Appendix C – Comparison between the actual and the virtual reservoir levels



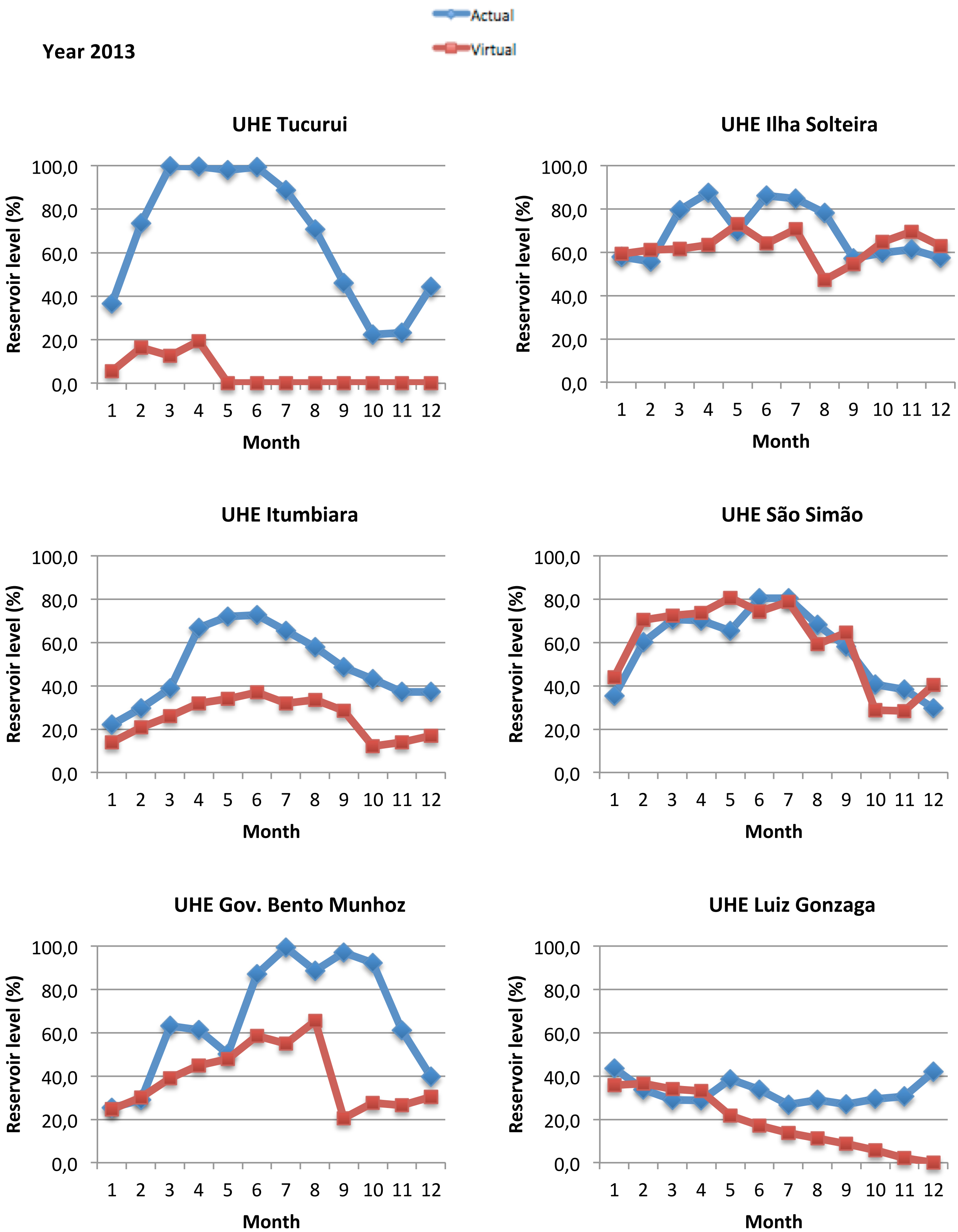

**Year 2012**



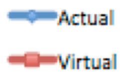
**Year 2012**

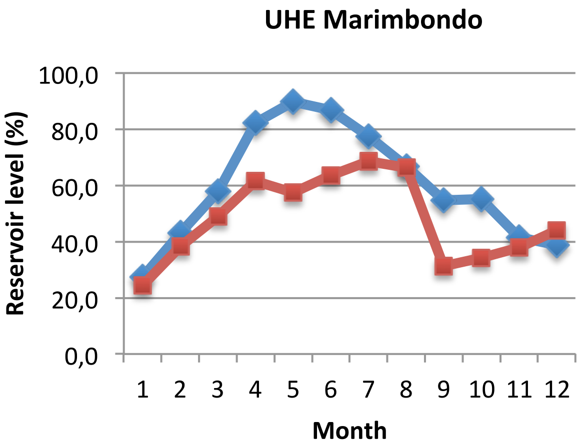

Actual
Virtual
UHE Marimbondo
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month
UHE Salto Santiago
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month
UHE Água Vermelha
Reservoir level (%)
100,00
80,00
60,00
40,00
20,00
0,00
1 2 3 4 5 6 7 8 9 10 11 12
Month

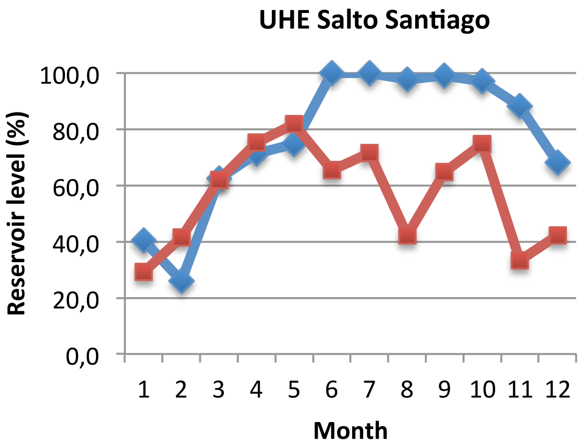
**Year 2013**

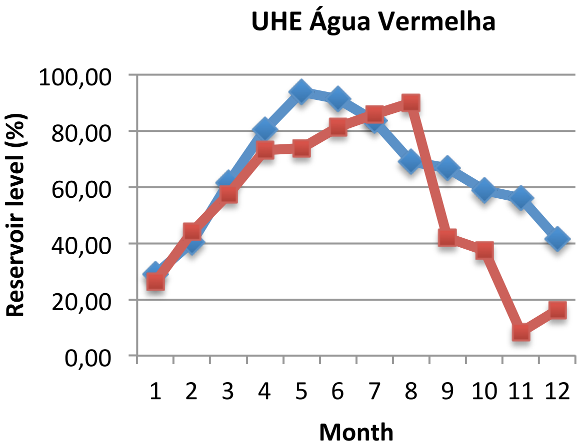

Actual
Virtual
UHE Tucurui
UHE Ilha Solteira
UHE Itumbiara
UHE São Simão
UHE Gov. Bento Munhoz
UHE Luiz Gonzaga
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month

**Year 2013**

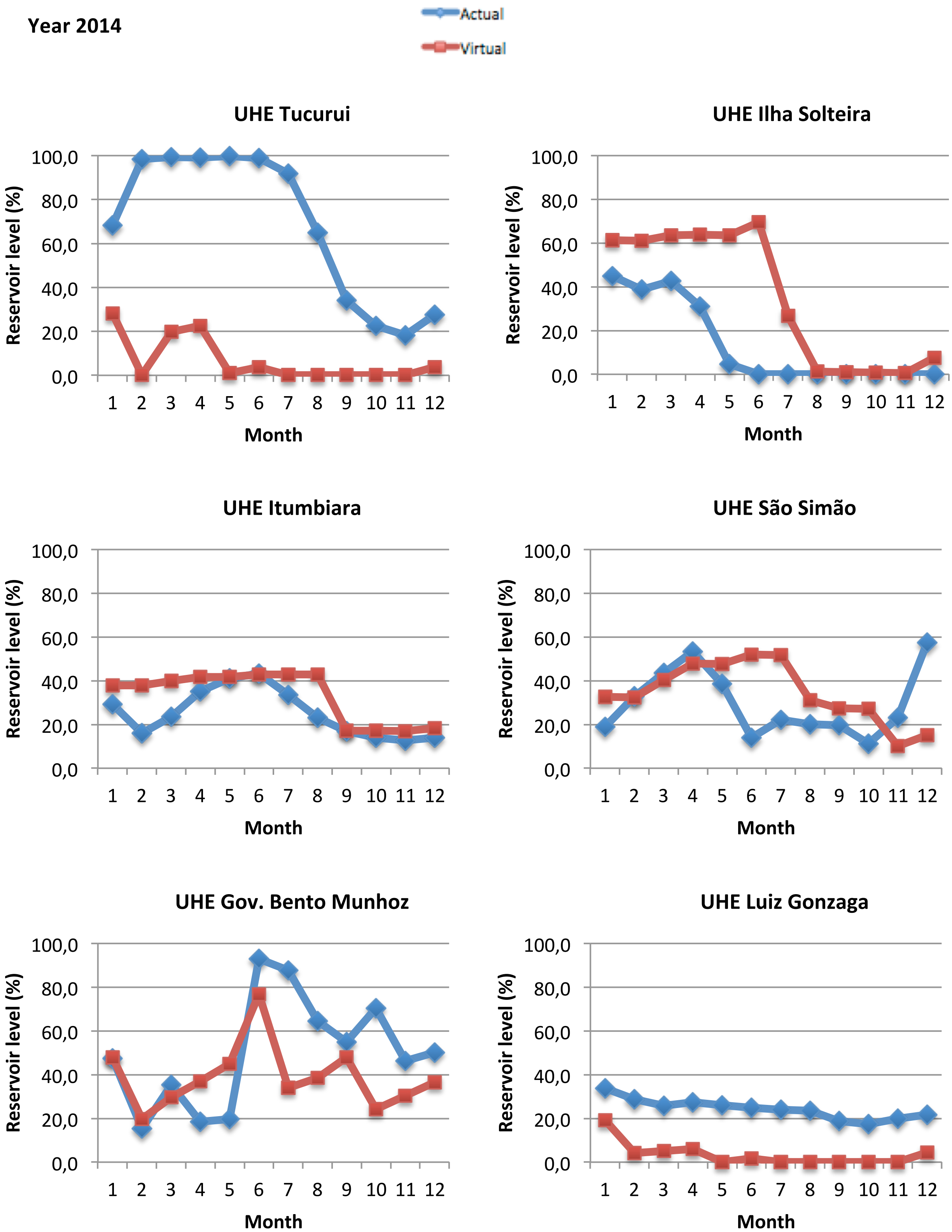

Actual
Virtual


UHE Marimbondo
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month

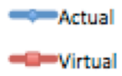

UHE Salto Santiago
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month

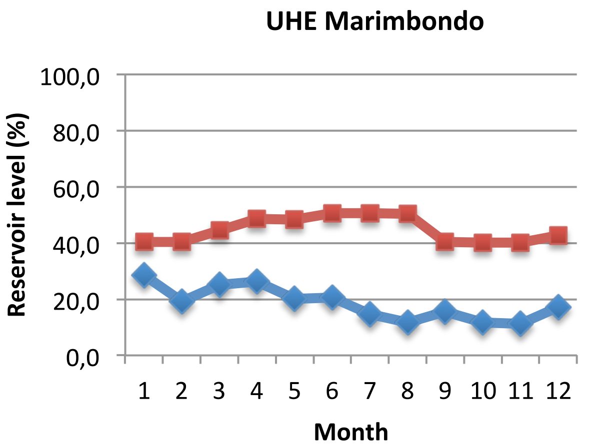

UHE Água Vermelha
Reservoir level (%)
100,00
80,00
60,00
40,00
20,00
0,00
1 2 3 4 5 6 7 8 9 10 11 12
Month

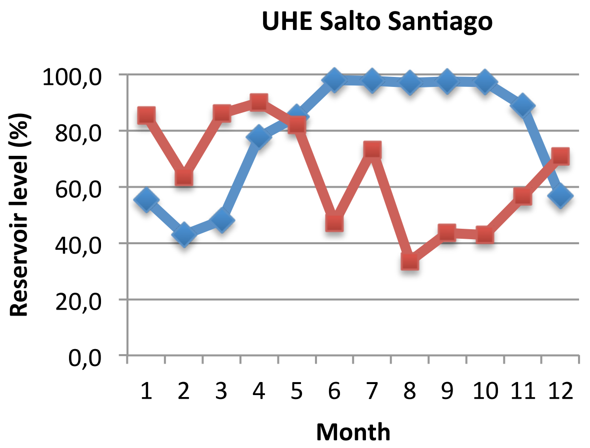
**Year 2014**

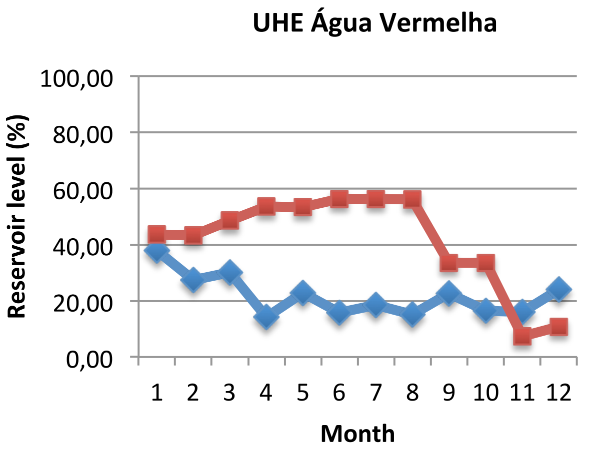

Actual
Virtual
UHE Tucurui
UHE Ilha Solteira
UHE Itumbiara
UHE São Simão
UHE Gov. Bento Munhoz
UHE Luiz Gonzaga
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month

**Year 2014**


Actual
Virtual


UHE Marimbondo
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month


UHE Salto Santiago
Reservoir level (%)
100,0
80,0
60,0
40,0
20,0
0,0
1 2 3 4 5 6 7 8 9 10 11 12
Month


UHE Água Vermelha
Reservoir level (%)
100,00
80,00
60,00
40,00
20,00
0,00
1 2 3 4 5 6 7 8 9 10 11 12
Month

# Appendix D – VRM simulations: Monte-Carlo sample

## Year 2012

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 1 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 74 | 288 | 240 | 160 | 77.7 | 77.66 | #DIV/0! | #DIV/0! |
| 2 | 2 | 3 | 11 | 29 | 68 | 18 | 52 | 69 | 183 | 233 | 240 | 160 | 89.0 | 83.34 | 64.51 | 6.81% |
| 3 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 147 | 233 | 172 | 64 | 67.0 | 77.90 | 121.26 | 8.16% |
| 4 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 69 | 110 | 233 | 240 | 64 | 71.8 | 76.38 | 90.02 | 6.21% |
| 5 | 2 | 3 | 11 | 69 | 68 | 18 | 13 | 69 | 183 | 288 | 308 | 160 | 99.3 | 80.97 | 172.78 | 7.26% |
| 6 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 110 | 288 | 240 | 160 | 84.3 | 81.52 | 140.06 | 5.93% |
| 7 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 69 | 147 | 233 | 240 | 256 | 90.9 | 82.86 | 129.20 | 5.19% |
| 8 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 147 | 288 | 240 | 112 | 79.7 | 82.47 | 111.98 | 4.54% |
| 9 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 110 | 233 | 240 | 64 | 69.6 | 81.04 | 116.30 | 4.44% |
| 10 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 44 | 74 | 288 | 240 | 112 | 72.0 | 80.14 | 111.48 | 4.17% |
| 11 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 233 | 240 | 112 | 75.6 | 79.73 | 102.18 | 3.82% |
| 12 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 94 | 147 | 288 | 308 | 64 | 87.1 | 80.34 | 97.37 | 3.55% |
| 13 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 233 | 172 | 64 | 66.0 | 79.23 | 105.14 | 3.59% |
| 14 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 94 | 147 | 288 | 240 | 160 | 87.9 | 79.85 | 102.43 | 3.39% |
| 15 | 2 | 3 | 11 | 29 | 68 | 18 | 52 | 44 | 110 | 178 | 308 | 64 | 73.9 | 79.46 | 97.44 | 3.21% |
| 16 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 74 | 178 | 240 | 112 | 69.7 | 78.85 | 96.84 | 3.12% |
| 17 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 147 | 233 | 172 | 160 | 73.5 | 78.54 | 92.48 | 2.97% |
| 18 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 94 | 147 | 178 | 308 | 64 | 74.8 | 78.33 | 87.81 | 2.82% |
| 19 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 147 | 288 | 240 | 112 | 81.8 | 78.51 | 83.57 | 2.67% |
| 20 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 110 | 233 | 172 | 112 | 70.1 | 78.09 | 82.74 | 2.60% |
| 21 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 147 | 233 | 240 | 112 | 77.2 | 78.05 | 78.64 | 2.48% |
| 22 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 147 | 178 | 172 | 64 | 66.1 | 77.51 | 81.33 | 2.48% |
| 23 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 288 | 308 | 160 | 89.8 | 78.05 | 84.25 | 2.45% |
| 24 | 2 | 3 | 11 | 69 | 31 | 18 | 13 | 44 | 147 | 288 | 308 | 112 | 87.1 | 78.42 | 83.98 | 2.39% |
| 25 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 147 | 233 | 240 | 112 | 77.2 | 78.38 | 80.54 | 2.29% |
| 26 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 288 | 240 | 208 | 84.7 | 78.62 | 78.85 | 2.22% |
| 27 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 110 | 233 | 240 | 112 | 77.3 | 78.57 | 75.88 | 2.13% |
| 28 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 147 | 233 | 240 | 112 | 76.7 | 78.50 | 73.20 | 2.06% |
| 29 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 233 | 240 | 160 | 79.6 | 78.54 | 70.63 | 1.99% |
| 30 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 147 | 233 | 240 | 64 | 73.2 | 78.36 | 69.13 | 1.94% |
| 31 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 288 | 240 | 112 | 76.7 | 78.31 | 66.91 | 1.88% |
| 32 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 233 | 240 | 160 | 76.1 | 78.24 | 64.91 | 1.82% |
| 33 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 110 | 123 | 240 | 112 | 66.6 | 77.89 | 67.00 | 1.83% |
| 34 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 183 | 288 | 172 | 112 | 79.2 | 77.93 | 65.02 | 1.77% |
| 35 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 74 | 288 | 104 | 160 | 71.6 | 77.75 | 64.26 | 1.74% |

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 36 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 110 | 233 | 240 | 112 | 74.2 | 77.65 | 62.77 | 1.70% |
| 37 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 110 | 288 | 376 | 160 | 94.1 | 78.09 | 68.33 | 1.74% |
| 38 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 110 | 288 | 308 | 64 | 80.4 | 78.15 | 66.62 | 1.69% |
| 39 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 44 | 147 | 233 | 308 | 112 | 83.9 | 78.30 | 65.72 | 1.66% |
| 40 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 44 | 147 | 288 | 172 | 64 | 73.2 | 78.17 | 64.69 | 1.63% |
| 41 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 147 | 178 | 240 | 112 | 72.7 | 78.04 | 63.81 | 1.60% |
| 42 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 233 | 240 | 160 | 79.6 | 78.08 | 62.32 | 1.56% |
| 43 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 44 | 147 | 178 | 240 | 112 | 69.0 | 77.87 | 62.77 | 1.55% |
| 44 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 74 | 288 | 240 | 160 | 79.2 | 77.90 | 61.34 | 1.52% |
| 45 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 110 | 233 | 172 | 64 | 67.7 | 77.67 | 62.26 | 1.51% |
| 46 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 94 | 147 | 233 | 240 | 112 | 79.3 | 77.70 | 60.94 | 1.48% |
| 47 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 44 | 74 | 288 | 240 | 112 | 72.0 | 77.58 | 60.30 | 1.46% |
| 48 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 94 | 74 | 233 | 240 | 64 | 70.8 | 77.44 | 59.98 | 1.44% |
| 49 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 119 | 110 | 233 | 308 | 208 | 92.1 | 77.74 | 63.09 | 1.46% |
| 50 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 147 | 288 | 240 | 64 | 77.2 | 77.73 | 61.81 | 1.43% |
| 51 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 110 | 233 | 172 | 160 | 74.1 | 77.66 | 60.83 | 1.41% |
| 52 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 44 | 147 | 233 | 240 | 112 | 76.8 | 77.64 | 59.66 | 1.38% |
| 53 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 44 | 74 | 233 | 240 | 208 | 75.5 | 77.60 | 58.60 | 1.35% |
| 54 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 69 | 110 | 233 | 240 | 112 | 74.2 | 77.54 | 57.70 | 1.33% |
| 55 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 288 | 240 | 64 | 76.2 | 77.51 | 56.67 | 1.31% |
| 56 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 38 | 288 | 240 | 112 | 75.9 | 77.48 | 55.69 | 1.29% |
| 57 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 19 | 110 | 233 | 240 | 160 | 72.4 | 77.39 | 55.15 | 1.27% |
| 58 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 44 | 147 | 233 | 172 | 64 | 67.0 | 77.22 | 56.04 | 1.27% |
| 59 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 69 | 110 | 233 | 104 | 160 | 70.0 | 77.09 | 55.95 | 1.26% |
| 60 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 183 | 233 | 172 | 112 | 72.5 | 77.02 | 55.35 | 1.25% |
| 61 | 2 | 3 | 11 | 69 | 68 | 18 | 33 | 44 | 74 | 178 | 172 | 112 | 65.3 | 76.83 | 56.67 | 1.25% |
| 62 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 94 | 183 | 233 | 104 | 112 | 74.2 | 76.78 | 55.85 | 1.24% |
| 63 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 147 | 288 | 172 | 112 | 74.1 | 76.74 | 55.07 | 1.22% |
| 64 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 69 | 110 | 288 | 240 | 64 | 76.4 | 76.74 | 54.19 | 1.20% |
| 65 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 44 | 147 | 288 | 104 | 64 | 67.5 | 76.59 | 54.65 | 1.20% |
| 66 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 19 | 110 | 178 | 240 | 160 | 69.5 | 76.49 | 54.58 | 1.19% |
| 67 | 2 | 3 | 11 | 69 | 68 | 18 | 13 | 44 | 147 | 288 | 172 | 112 | 78.9 | 76.52 | 53.84 | 1.17% |
| 68 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 288 | 172 | 112 | 71.0 | 76.44 | 53.48 | 1.16% |
| 69 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 147 | 288 | 240 | 64 | 79.3 | 76.48 | 52.81 | 1.14% |
| 70 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 19 | 147 | 288 | 240 | 112 | 79.2 | 76.52 | 52.15 | 1.13% |
| 71 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 74 | 233 | 308 | 64 | 70.7 | 76.44 | 51.88 | 1.12% |
| 72 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 74 | 233 | 308 | 64 | 70.7 | 76.36 | 51.60 | 1.11% |
| 73 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 147 | 288 | 240 | 112 | 83.3 | 76.46 | 51.54 | 1.10% |
| 74 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 44 | 110 | 288 | 240 | 64 | 75.8 | 76.45 | 50.84 | 1.08% |
| 75 | 2 | 3 | 11 | 29 | 68 | 18 | 33 | 94 | 183 | 233 | 240 | 160 | 89.5 | 76.62 | 52.43 | 1.09% |

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 76 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 94 | 110 | 178 | 172 | 160 | 70.1 | 76.54 | 52.29 | 1.08% |
| 77 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 147 | 233 | 240 | 112 | 75.1 | 76.52 | 51.63 | 1.07% |
| 78 | 2 | 3 | 11 | 29 | 31 | 18 | 52 | 44 | 147 | 288 | 172 | 64 | 71.7 | 76.46 | 51.25 | 1.06% |
| 79 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 94 | 147 | 233 | 240 | 160 | 81.7 | 76.52 | 50.95 | 1.05% |
| 80 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 178 | 308 | 64 | 72.7 | 76.48 | 50.49 | 1.04% |
| 81 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 183 | 178 | 172 | 160 | 75.6 | 76.46 | 49.86 | 1.03% |
| 82 | 2 | 3 | 11 | 29 | 68 | 18 | 13 | 69 | 74 | 233 | 240 | 112 | 72.7 | 76.42 | 49.42 | 1.02% |
| 83 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 288 | 172 | 112 | 71.0 | 76.35 | 49.17 | 1.01% |
| 84 | 2 | 3 | 11 | 29 | 31 | 18 | 13 | 69 | 147 | 288 | 240 | 112 | 80.2 | 76.40 | 48.75 | 1.00% |
| 85 | 2 | 3 | 11 | 29 | 31 | 18 | 33 | 44 | 110 | 233 | 240 | 64 | 68.1 | 76.30 | 48.98 | 0.99% |

**Year 2013**

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 1 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 209 | 68 | 89.1 | 89.11 | #DIV/0! | #DIV/0! |
| 2 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 209 | 68 | 85.2 | 87.13 | 7.85 | 2.27% |
| 3 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 209 | 68 | 93.2 | 89.17 | 16.35 | 2.62% |
| 4 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 209 | 68 | 85.2 | 88.16 | 14.94 | 2.19% |
| 5 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 209 | 68 | 85.2 | 87.56 | 13.02 | 1.84% |
| 6 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 270 | 68 | 90.3 | 88.01 | 11.62 | 1.58% |
| 7 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 209 | 68 | 93.2 | 88.76 | 13.59 | 1.57% |
| 8 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 209 | 68 | 85.2 | 88.31 | 13.27 | 1.46% |
| 9 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 65 | 157 | 209 | 68 | 82.5 | 87.66 | 15.36 | 1.49% |
| 10 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 109 | 209 | 68 | 82.7 | 87.16 | 16.15 | 1.46% |
| 11 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 204 | 270 | 68 | 98.2 | 88.16 | 25.57 | 1.73% |
| 12 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 157 | 270 | 68 | 91.7 | 88.46 | 24.30 | 1.61% |
| 13 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 209 | 68 | 93.2 | 88.83 | 24.03 | 1.53% |
| 14 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 157 | 270 | 68 | 91.7 | 89.03 | 22.79 | 1.43% |
| 15 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 157 | 331 | 68 | 96.8 | 89.55 | 25.20 | 1.45% |
| 16 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 209 | 68 | 89.1 | 89.53 | 23.54 | 1.35% |
| 17 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 109 | 209 | 68 | 82.7 | 89.12 | 24.84 | 1.36% |
| 18 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 147 | 68 | 88.1 | 89.07 | 23.43 | 1.28% |
| 19 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 157 | 270 | 68 | 91.7 | 89.21 | 22.50 | 1.22% |
| 20 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 109 | 147 | 68 | 84.2 | 88.96 | 22.58 | 1.19% |
| 21 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 204 | 270 | 68 | 95.7 | 89.28 | 23.61 | 1.19% |
| 22 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 109 | 209 | 68 | 82.7 | 88.98 | 24.47 | 1.19% |
| 23 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 204 | 270 | 68 | 98.2 | 89.38 | 27.04 | 1.21% |
| 24 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 147 | 68 | 88.1 | 89.32 | 25.93 | 1.16% |
| 25 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 209 | 68 | 85.2 | 89.16 | 25.55 | 1.13% |
| 26 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 209 | 68 | 89.1 | 89.16 | 24.53 | 1.09% |
| 27 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 157 | 270 | 68 | 94.2 | 89.34 | 24.53 | 1.07% |
| 28 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 115 | 109 | 209 | 68 | 82.7 | 89.10 | 25.22 | 1.07% |
| 29 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 164 | 157 | 270 | 68 | 98.3 | 89.42 | 27.26 | 1.08% |
| 30 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 109 | 270 | 68 | 90.3 | 89.45 | 26.34 | 1.05% |
| 31 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 70 | 115 | 62 | 270 | 68 | 86.3 | 89.35 | 25.78 | 1.02% |
| 32 | 102 | 51 | 78 | 46 | 91 | 56 | 28 | 40 | 164 | 109 | 209 | 68 | 86.8 | 89.27 | 25.16 | 0.99% |

**Year 2014**

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 1 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 489 | 518 | 413 | 212 | 267.1 | 267.08 | #DIV/0! | #DIV/0! |
| 2 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 609 | 518 | 544 | 212 | 287.9 | 277.50 | 217.35 | 3.76% |
| 3 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 482 | 489 | 518 | 413 | 212 | 276.6 | 277.19 | 108.96 | 2.17% |
| 4 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 254 | 489 | 642 | 544 | 212 | 278.8 | 277.59 | 73.27 | 1.54% |
| 5 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 413 | 212 | 246.8 | 271.43 | 244.87 | 2.58% |
| 6 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 482 | 489 | 394 | 544 | 212 | 288.2 | 274.22 | 242.85 | 2.32% |
| 7 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 489 | 394 | 544 | 212 | 278.7 | 274.87 | 205.26 | 1.97% |
| 8 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 482 | 250 | 518 | 544 | 212 | 267.5 | 273.94 | 182.78 | 1.74% |
| 9 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 250 | 394 | 413 | 212 | 247.9 | 271.05 | 235.37 | 1.89% |
| 10 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 482 | 250 | 642 | 413 | 212 | 278.0 | 271.74 | 214.09 | 1.70% |
| 11 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 283 | 212 | 235.9 | 268.49 | 309.42 | 1.98% |
| 12 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 544 | 212 | 279.1 | 269.37 | 290.60 | 1.83% |
| 13 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 254 | 250 | 394 | 544 | 212 | 238.2 | 266.97 | 341.29 | 1.92% |
| 14 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 250 | 394 | 544 | 212 | 247.7 | 265.59 | 341.68 | 1.86% |
| 15 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 609 | 518 | 413 | 212 | 277.1 | 266.35 | 326.05 | 1.75% |
| 16 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 482 | 489 | 642 | 544 | 212 | 297.8 | 268.31 | 365.97 | 1.78% |
| 17 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 254 | 370 | 394 | 544 | 212 | 259.2 | 267.78 | 347.95 | 1.69% |
| 18 | 82 | 314 | 216 | 215 | 215 | 116 | 278 | 368 | 489 | 394 | 413 | 212 | 276.0 | 268.24 | 331.20 | 1.60% |
| 19 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 413 | 212 | 246.8 | 267.11 | 337.04 | 1.58% |
| 20 | 82 | 314 | 216 | 215 | 215 | 116 | 278 | 482 | 489 | 394 | 413 | 212 | 285.5 | 268.02 | 336.14 | 1.53% |
| 21 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 413 | 212 | 246.8 | 267.01 | 340.84 | 1.51% |
| 22 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 544 | 212 | 268.7 | 267.09 | 324.74 | 1.44% |
| 23 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 413 | 212 | 257.1 | 266.66 | 314.33 | 1.39% |
| 24 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 413 | 212 | 257.9 | 266.29 | 303.88 | 1.34% |
| 25 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 544 | 212 | 279.1 | 266.80 | 297.73 | 1.29% |
| 26 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 250 | 394 | 544 | 212 | 247.7 | 266.06 | 299.92 | 1.28% |
| 27 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 544 | 212 | 279.1 | 266.54 | 294.64 | 1.24% |
| 28 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 413 | 212 | 257.1 | 266.21 | 286.92 | 1.20% |
| 29 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 254 | 370 | 518 | 674 | 212 | 280.4 | 266.70 | 283.64 | 1.17% |
| 30 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 489 | 518 | 413 | 212 | 267.1 | 266.71 | 273.87 | 1.13% |
| 31 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 283 | 212 | 246.2 | 266.05 | 278.27 | 1.13% |
| 32 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 413 | 212 | 268.2 | 266.12 | 269.43 | 1.09% |

| # | monthly *PLD* (R$) | | | | | | | | | | | | F | E(F) | V(F) | β |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | | | | |
| 33 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 394 | 544 | 212 | 268.7 | 266.20 | 261.22 | 1.06% |
| 34 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 518 | 674 | 212 | 289.9 | 266.89 | 269.86 | 1.06% |
| 35 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 254 | 489 | 270 | 544 | 212 | 247.8 | 266.35 | 272.33 | 1.05% |
| 36 | 82 | 181 | 216 | 215 | 215 | 116 | 181 | 482 | 489 | 518 | 283 | 212 | 265.7 | 266.33 | 264.56 | 1.02% |
| 37 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 254 | 370 | 394 | 413 | 212 | 248.4 | 265.85 | 265.93 | 1.01% |
| 38 | 82 | 314 | 216 | 215 | 215 | 116 | 181 | 368 | 370 | 642 | 544 | 212 | 289.4 | 266.46 | 273.31 | 1.01% |
| 39 | 82 | 181 | 216 | 215 | 215 | 116 | 375 | 368 | 250 | 394 | 544 | 212 | 263.9 | 266.40 | 266.29 | 0.98% |